AN EVALUATION OF COMPLETION PARAMETERS AND WELL PERFORMANCE IN THE MONTNEY FORMATION IN BRITISH COLUMBIA, CANADA

A Thesis

by

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ABSTRACT

The objectives of this study are to quantify the influence of individual completion parameters on the production in complex shale/tight gas formations and to predict production from large completion datasets of public domain information without having in-depth reservoir characterization.

Shale gas has become an increasingly significant source of energy in the last decade especially in the U.S. and Canada. Improving completion technologies in long horizontal wells makes these plays one of the most attractive investment opportunities in oil and gas industry. The Montney is one of largest shale gas plays in Canada covering a large area in northeast British Columbia and Alberta.

Advanced horizontal drilling technology makes unconventional resources economically viable in the Montney formation, which now has a production rate of 1.5 Bcf/day. Well quality, well costs and the provincial government royalty programs vary throughout the play. In addition, various operators are attempting a variety of horizontal leg lengths and completion techniques. All these variables, in combination, create difficulty in adequately comparing economic outcomes in different areas. In this research, more than 430 completion reports of horizontal wells in British Columbia have been reviewed. Multivariate regression analysis has been applied to study correlations between production rate indicators (Initial Production, EUR) and completion attributes (Lateral length, number of fracture stages, number of perforation clusters, fracture fluid). Using regression analysis on completion parameters and best average 12 consecutive

months of production showed that number of fracture stages and perforation clusters have the most impact on the well performance. More fracture sand results in more production, but a large amount of uncertainty exists. Fluid and lateral length do not have a strong positive correlation with production rate. Applying regression analysis, the best model for predicting production rate was selected and used in an economic analysis performed using Value Navigator software to calculate and map net present value and rate of return maps.

Our goal is to present a solution technique to help optimize completions in complex shale reservoirs. Since many undrilled locations remain, completion optimization has significant value.

DEDICATION

To my Mom, the best in the world for her love and support

To my Dad , up above the heavens for love and care in his short life

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NOMENCLATURE

B1	First best month production
B12	Twelve months best production
DOFP	Date of first production
EUR	Estimated ultimate recovery
FS	Fracture stages
FWHP	Flow well head pressure, PSI
IP	Initial production
LL	Lateral length
Mcf	1000 cubic feet
Mcfed	1,000 cubic feet equivalent per day
MMcf/day	Million cubic feet per day
NEB	National energy board
NVP10	Net present value 10%
OGIP	Original gas in place
OOIP	Original oil in place
P10	10% probability of occurrence
P50	50% probability of occurrence
P90	90% probability of occurrence
PC	Perforation cluster
ROR	Rate of return

SICP	Shut in case pressure, PSI
TCF	Trillion cubic feet
TOE	Tonnes of oil equivalent
TVD	True vertical depth
UG	Unconventional gas
UGR	Unconventional gas resources
UWI	Unique well identifier
VBA	Visual Basic Application

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1. INTRODUCTION

1.1 Why This Work is Important

Well completion parameters such as FS, PC, LL, and Fluid are thought to have a significant impact on well performance. Quantifying this impact is required to perform any type of completion optimization. This study applies multivariate regression analysis using public domain completion and production data to determine which completion parameters have the biggest impact on production. In this method, no log analysis or reservoir simulation is required. The methodology is suitable for complex formations with many data points such as shale gas with horizontal wells and multiple fracture stages. Natural variability in reservoir quality and various completion techniques makes it difficult to discern answers without this technique. In this study, single variable (2-D) regression does not reveal any clear relation between well performance and completion parameters due to the multiple influential variables in these formations.

This method has been applied to a Montney completion database, which is part of this research. The Montney is a horizontal-well play that covers a large area in northeast British Columbia and Alberta with thousands of future wells and a great deal of potential value in completion optimization. This formation is in the early stage of development with over 10,000 remaining well locations.

Geological and historical production data have been collected from about 1400 wells. There are several uncertainties about influential parameters on well performance. The primary purpose of this research is to find an approach that can quantify the impact of best completion practices based on production and completion data and to predict well performance from completion data alone. This method can easily be applied to other shale gas formations where completion and production data are available on a large number of wells.

2. NATURAL GAS RESOURCES

This chapter is an overview of the conventional and unconventional natural gas resources. Three common types of unconventional resources and their distributions all throughout the world are discussed. Finally, a review of Montney formation is presented.

2.1 Energy Demand in Future

Energy demand will increase in next few decades and due to limited conventional resources, we need to pay more attention to and explore for unconventional resources. Population and income growth are the main reasons for increasing worldwide energy demand. “By 2030 world population is projected to reach 8.3 billion, which means an additional 1.3 billion people will need energy; and world income in 2030 is expected to be roughly double the 2011 level in real terms. World primary energy consumption is projected to grow by 1.6% p.a. from 2011 to 2030, adding 36% to global consumption by 2030. The growth rate declines, from 2.5% p.a. for 2000-10, to 2.1% p.a. for 2010-20, and 1.3% p.a. from 2020 to 2030.”[1] (Fig. 1)

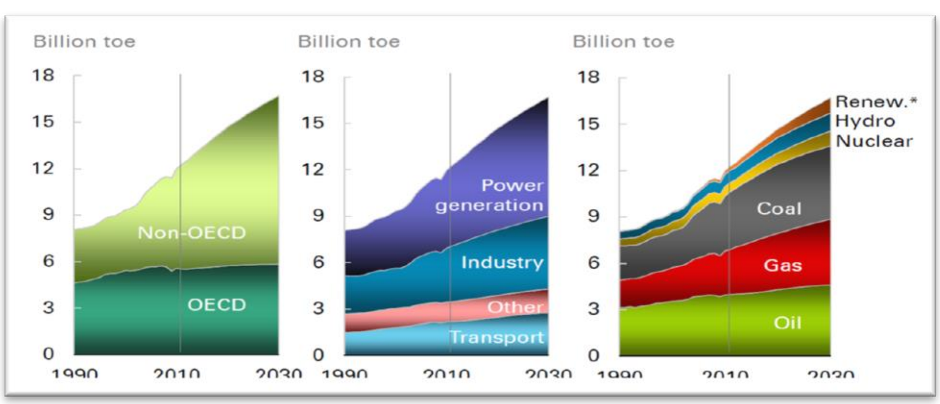


Fig.1- Energy demand in next two decades [1]

2.2 Conventional Resources

Conventional hydrocarbons are economically recoverable resources which can be extracted by common and conventional methods, can be drilled easily and may not need hydraulic fracturing. Conventional resources are usually characterized by highly interconnected permeability. [2] Typically, the recovery factor of these resources is over 80 percent, requiring only vertical wells to produce. These conventional resources will provide a decreasing share of energy demand. Unconventional resources will likely supply most of the total energy in the future.

2.3 Unconventional Resources

Conventional resources are limited and we need to focus on the exploration and development of unconventional resources. Unconventional gas (UG) resources are usually located in low permeability rocks and do not produce commercially without stimulation. The gas in unconventional resources is highly dispsred in rock system and hydralic fracturing is required for the gas to flow to the well bore. Unconventional gas accumulations are distributed over a large area compared to conventional resources. These resources are tremendously complex and hetrogeneous. The recovery factor in UG is 15-50%, which is much less than in conventional resources. The decline of conventional resources, technology improvement and high gas prices make unconventional natural gas popular. The main types of natural gases are tight sands, coal bed methane and shale gas as shown in Fig. 2.

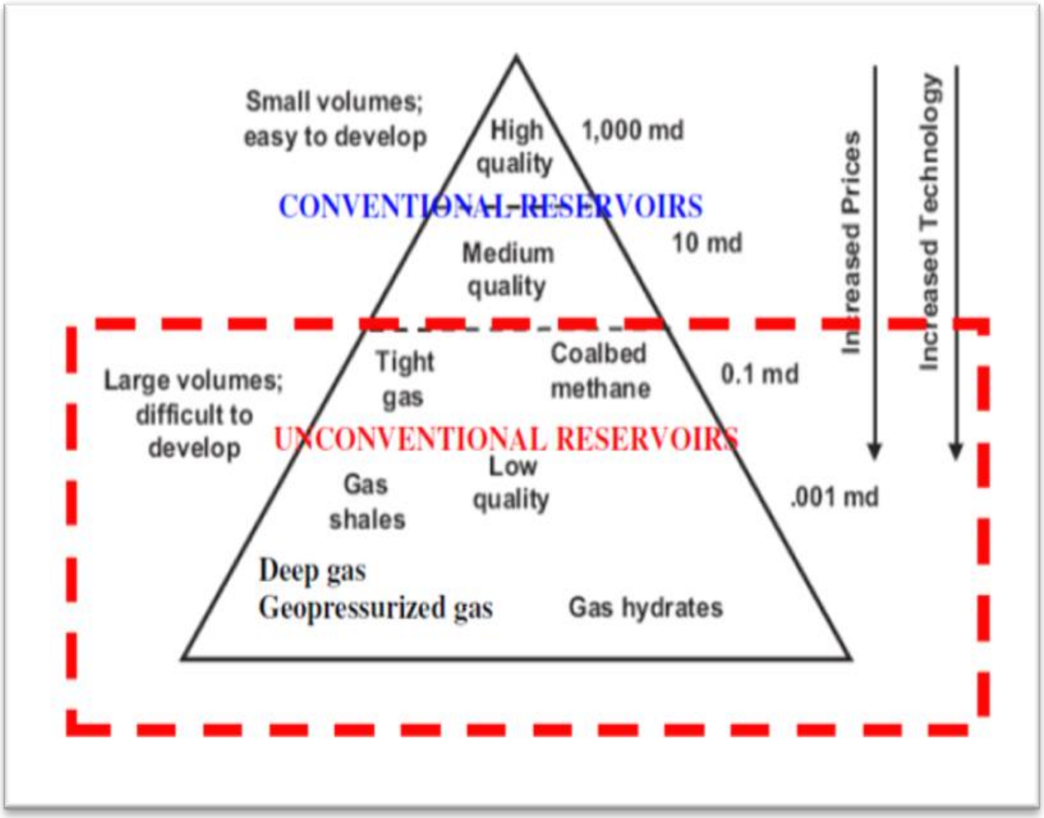


Fig. 2- Natural gas resource triangle [3]

As shown in Fig. 2, the permeability of conventional resources is greater than unconventional resources by the order of 102 to 106. Fig. 3 is schematic of the deposition of three types of unconventional resources.

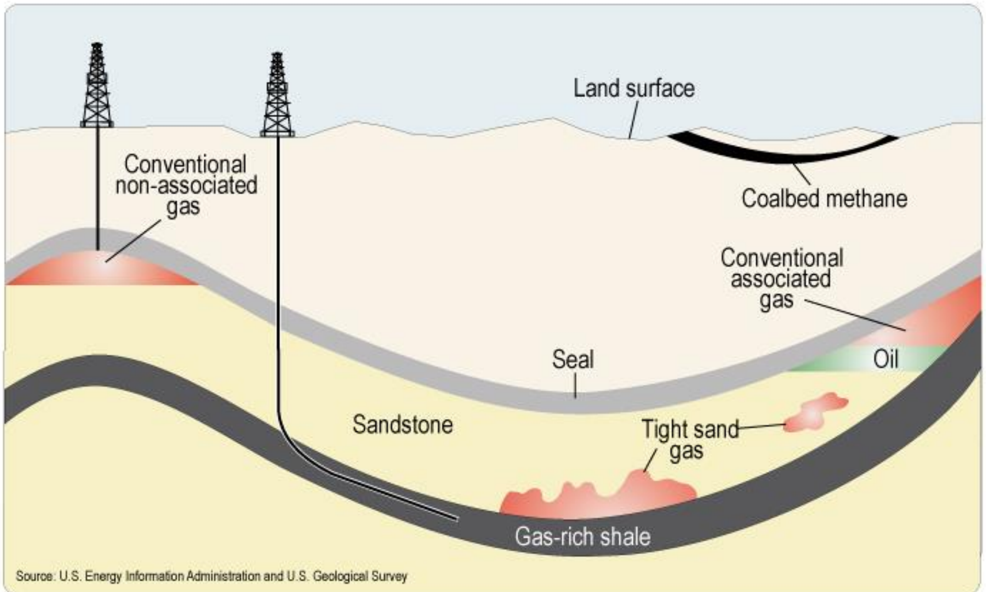


Fig. 3- Three types of unconventional gas resources

2.3.1 Tight Gas and Oil Sands

Tight gas and oil sands are low permeability reservoirs that produce natural gas. [3] Massive stimulation treatments are required to produce these resources economically. A definition for tight gas issued by the U.S. government is one in which the expected value of permeability to gas would be less than 0.1 md. This definition has been used to determine which gas wells would receive federal and/or state tax credits for producing from tight reservoirs. In reality, the definition of a tight gas reservoir is a function of many physical and economic factors. [4] Another definition is a reservoir that "cannot be economically produced volumes of natural gas unless a special technique is used to stimulate production. Specifically, large hydraulic fracture treatments, a horizontal well bore, or multilateral wellbores must be used to stimulate flow rates and increase the recovery efficiency in the reservoir." [5, 6]

2.3.2 Coalbed Methane

Coalbed methane (CBM) is a tremendous energy source potential that stores gas at densities of up to seven times the conventional reservoir gas volume. Estimated reserves are 7,500 trillion cubic feet globally with more than 700 trillion cubic feet in the United States alone.[7]

Coal and natural gas are formed under the same geological conditions. Coal deposits are usally found in seams. Coal seams contain natural gas, either within the seam itself or the surrounding rock. Until the reservoir pressure is dropped trapped methane in the coal is not gennerally released. In past decades CBM was known as a nuisance in the coal mining industry since the methane in the extracted coal usually leaked into mine itself becoming a safety hazard. Because of the saftey threat posed by accumulated methane in the coal mine, the methane was often vented to the atmosphere. Currently methane is extracted and injected into natural gas pipelines for sale, used as an industrial feedstock, or used for heating and electricity generation.[4,6]

2.3.3 Shale Gas

Shale formations contain very fine-grained sedimentary rock, which is breakable into thin, parallel layers. "These shales have natural gas, generally when two thick, black shale deposits 'sandwich' a thinner area of shale. Due to shale gas low permealbility, the natural gas extraction from shale formations is more challenging and more expensive compared to conventional natural gas". [6] The low recovery factor and production rate of shale gas wells made them unfavorable despite knowing their huge potential. Advanced horizontal drilling technology and multistage hydralic fracturing led to a significant increase in reserves all over world, specillay in North America. Including data from drilling results in new shale fields, such as the Marcellus, Haynesville, and Eagle Ford shale, U.S. Energy Information Administration (EIA) estimates, technically recoverable shale gas reserves to be about 428 trillion cubic feet (Tcf) in 2012 [8]. The Montney formation, which we study in this research, is a shale gas formation with 50 + Tcf of recoverable natural gas.

2.4 Unconventional Gas Distribution

Unconventional gas is distributed all over the world. In the US and Canada the majority of investment into unconventional gas resources occur compared to the rest of the world. More than 46% of the U.S. total gas production comes from unconventional resources. The United states is blessed with a huge unconventional resource, especially shale gas. More than 25 basins in Canda and the U.S. are producing substansial volumes of the hydrocarbon daily. Limited data have been gathered about the unconventional resources outside of North America. Fig. 4 shows the distribution of both conventional and unconventional resources around the world.

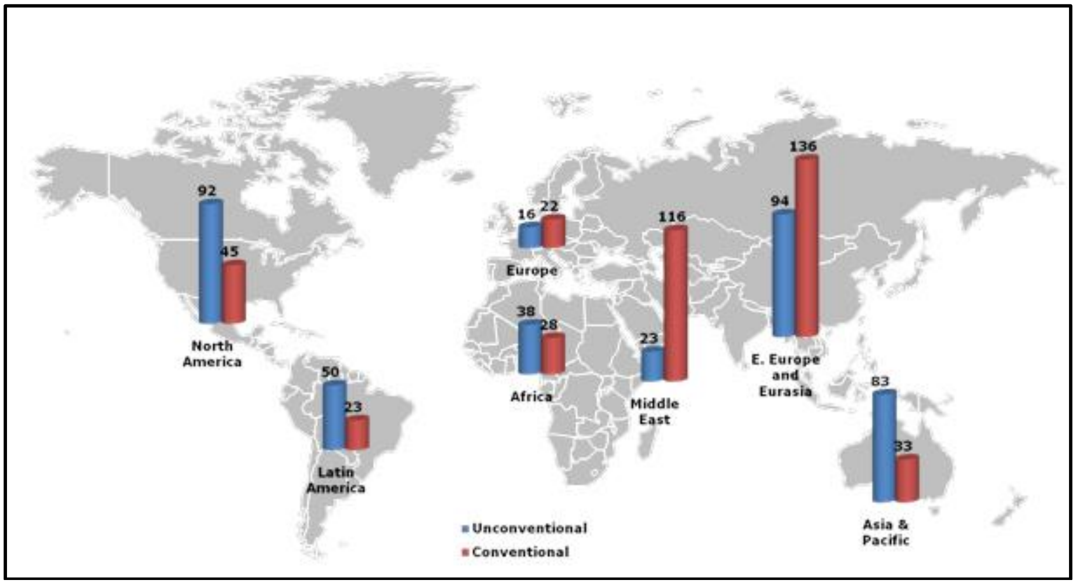


Fig. 4- Natural gas (both conventional and unconventional) per region expressed in billion m ^{3} (January 2010)

2.4.1 Unconventional Gas Distribution in North America

In order for the energy supply to satisfy energy demand, the U.S. exploration and production of unconventional resources has been rapidly increasing. Out of 74 trillion cubic meters (tcm) of remaining recoverable resources of natural gas at the of end-2011, half are unconventional. CBM resources are found mostly in the Rocky Mountain states of Wyoming, Utah, New Mexico, Colorado and Montana. Tight gas and shale gas are located in a number of different basins stretching across large parts of the United States, some of which are shared with Canada and Mexico. Four of the largest shale plays that have been identified, the Montney, Marcellus, Eagle Ford and Haynesville formations, taken as single reservoirs, are among the largest known gas fields of any type in the world. [8]As presented in Table 1, shale gas with 32% (24 tcm) of recoverable resources at the end of 2011 is the main UG resource in the U.S. After that, tight gas with 10 tcm has the second rank and CBM (3 tcm) has the third rank in the US.

Table 1- Unconventional gas distribution in North America

	Recoverable resources (tcm)		Production (bcm)		
	End-2011	Share of total	2005	2010	Share of total (2010)
Unconventional gas	37	50%	224	358	59%
Shale gas	24	32%	21	141	23%
Tight gas	10	13%	154	161	26%
Coalbed methane	3	4%	49	56	9%
Conventional gas	37	50%	288	251	41%
Total	**74**	**100%**	**511**	**609**	**100%**

Sources: IEA analysis and databases.

In Canada conventional and unconventional resources are estimated to be almost 4,000 Tcf. In recent decades, the exploration of UG resources changed the picture of potential resources in Canada dramatically (Table 2). Canada's marketable natural gas resource potential was estimated to be between 700 and 1300 Tcf. [9] Canada produces six Tcf/year of natural gas and 48% of the marketable gas comes from unconventional resources (presented in Table 3). Only 16% of coal bed Methane, 36% of tight gas and 30% of shale gas are estimated as the marketable gas, which is still quite a low portion of their potential.

Table 2- Canada gas in place resources (Tcf) [9]

CANADA'S GAS IN PLACE RESOURCES (TCF)	
Conventional (Remaining GIP)	692
Natural Gas from Coal/Coalbed Methane	801
Tight Gas	1311
Shale Gas	1111
TOTAL	3915

Table 3- Canada estimates marketable gas resources (Tcf) [9]

CANADA'S ESTIMATED MARKETABLE GAS RESOURCES (TCF)	
Conventional (Remaining GIP)	357
Natural Gas from Coal/Coalbed Methane	34 - 129
Tight Gas	215 - 476
Shale Gas	128-343
TOTAL	733 - 1304

2.4.2 Unconventional Gas Distribution Worldwide

Unconventional gas resources have been studied outside the North America, especially in recent years. One of the main challenges in developing UG around the world is a shortage of technology and expertise. Terasaki and Fujiti suggested a key to the problem of raising the production rate of UG around the world [10]. The solution is to transfer and export the U.S. advanced technology and expericences to other countries, this is predicted to have major effect on increasing the production rate of UG worldwide. [11]

In recent decades, interest for exploring and developing UG has increased. In Australia, commercial production of CBM projects has been reported. Also China and India are in the early stages of developing CBM projects**.** Rogner estimated the U.S. holds first place in shale gas resources with 1,372 Tcf ; Latin America holds first place in tight gas with 1,239 Tcf and former soviet union holds first place in coalbed methane with 4,000 Tcf. Table 4 shows global UG in place estimated by Rogner. [12]

Table 4- Estimation of unconventional gas in place by Rogner [12]

Region	CBM (Tcf)	GS (Tcf)	TS (Tcf)
North America	3,018.40	3,841.60	1,372
Latin America & Caribbean	39.2	2,116.80	1,293.60
Western Europe	156.8	509.6	352.8
Central & Eastern Europe	117.6	39.2	78.4
Former Soviet Union	3,959.20	627.2	901.6
Middle East & North Africa	0	2,548	823.2
Sub-Saharan Africa	39.2	274.4	784
Central Asia & China	1,215.20	3,528	352.8
Pacific OECD	470.4	2,312.80	705.6
Other Pacific Asia	0	313.6	548.8
South Asia	39.2	0	196
World	9,055.20	16,111.20	7,408.80

2.4.3 Introduction to Montney Formation

Montney production has increased by the implementation of multi-stage horizontal wells. Currently the Montney has become one of the most important UG plays in the Western Canadian sedimentary basin. It is located largely in North-East British Columbia and North-West Alberta (Fig. 5). In this study, we focus on the British Columbia portion of the play.

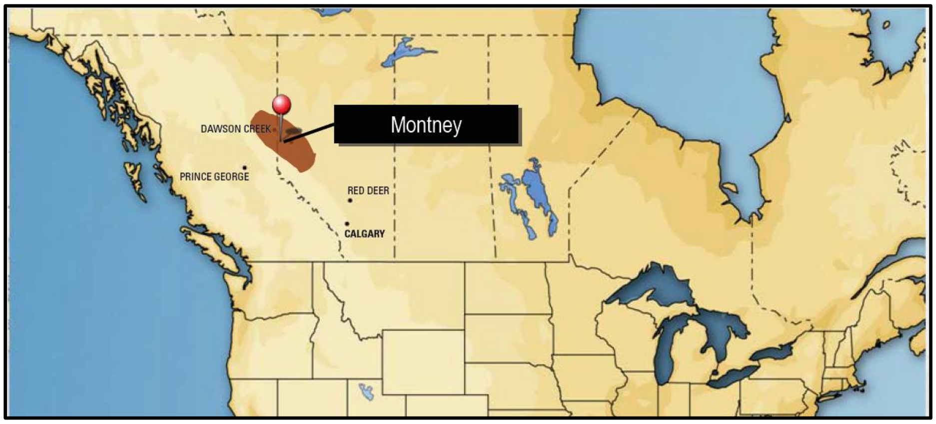


Fig. 5- Montney formation

The first modern Montney well was drilled in North Eastern British Columbia in 2005. However, the huge potential of Montney formation was found after the advent of multi-stage fracturing technology in late 2006. Fig. 6 shows that how increasing the number of fracture stages will result in higher production rates.

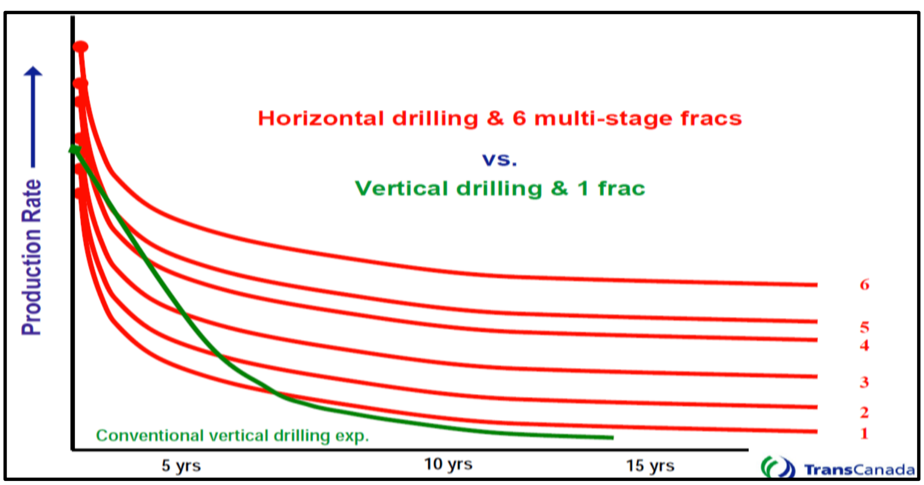


Fig. 6- Comparison of vertical and multi-stage horizontal decline curves

“Prior to 2007, the Montney formation was relatively unexploited, with less than 50 MMcf/D being produced from mostly vertical wells near the Alberta/British Columbia border. Beginning in 2007, several companies (notably EnCana and ARC Resources) began testing the Montney with horizontal wellbores and multi-zone completions. As it is shown in Fig. 7 Montney play rapidly grew in BC, to 400+ horizontal wells and 1.1 Bcf/D by summer 2011.” [13]

In the early development stages companies focused on the most prolific Montney zone, the upper Montney with a thickness of 300 meters (~1000 ft.). Currently 90 percent of existing wells are drilled in the upper Montney while just 10 percent are in the lower Montney, but the lower Montney production is growing rapidly. The average Montney reservoir pressure is 2500 to 3000 psi (17237 Kpa to 20684 Kpa) and the average reservoir temperature is 175ºF / 80ºC with a highly heterogeneous and complex geology.

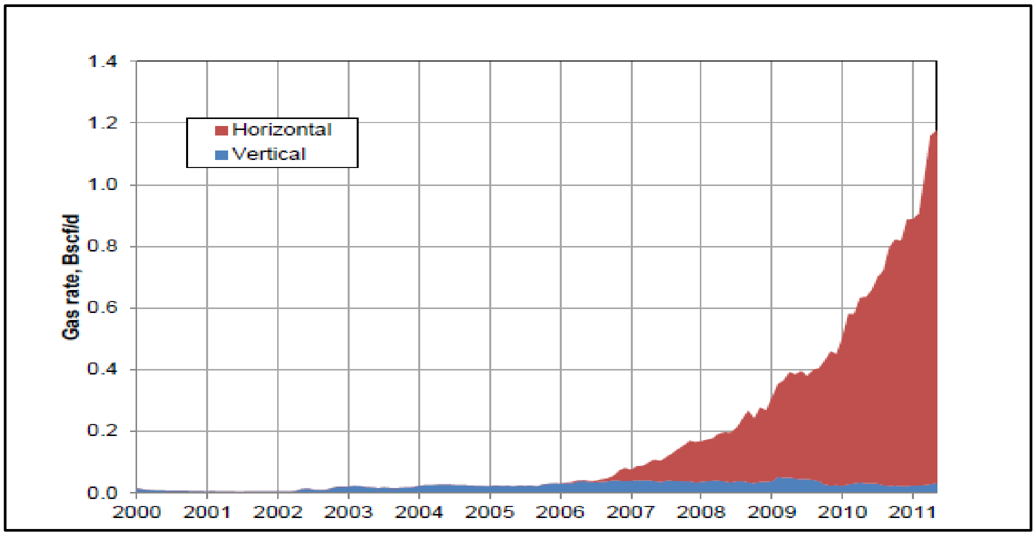


Fig. 7- BC Unconventional Montney gas production

2.4.4 Montney Geology

"The Montney Formation is a strati-graphical unit of Lower Triassic age in the Western Canadian Sedimentary Basin in British Columbia and Alberta with variations in characteristics over the play. The formation is composed of siltstone and dark grey shale, with dolomitic siltstone in the base and fine-grained sandstone towards the top. The facies is shaley in the north and west of the extent (Fort St. John), silty in the center (Dawson Creek and Pouce Coupe areas) and becomes coarser (sandy) in western Alberta (Valley view area)." [13, 14, 15]

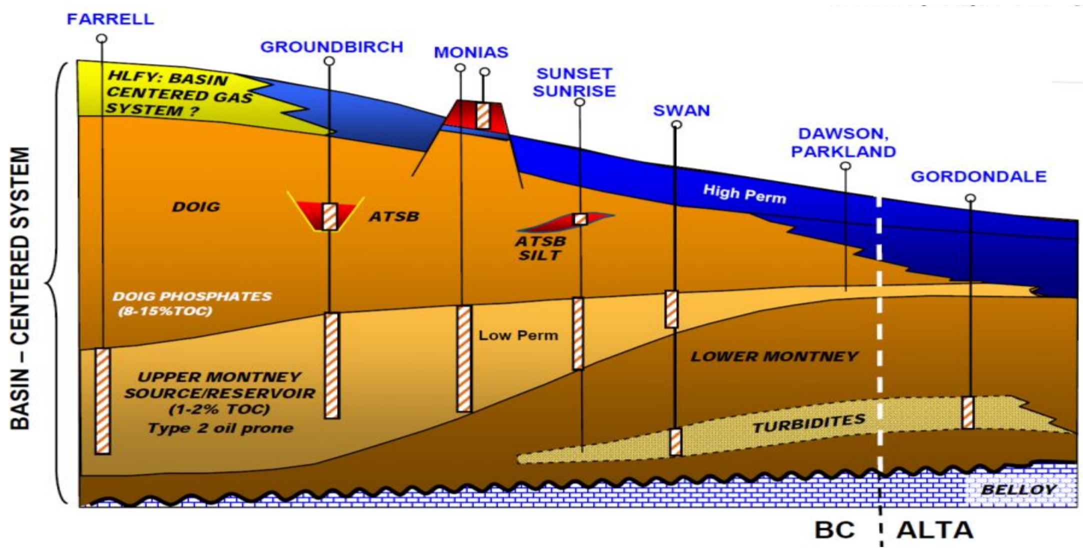


Fig. 8- Montney Upper, Middle and Lower pays

The majority of the Montney is made up of extremely low permeability highly laminated organic clay, silt, and fine sand (Nieto et al., 2009). Reservoir quality in the Montney is variable. The upper and Lower Montney are deposited in cycles on a scale of tens of meters in thickness, each cycle containing fine scale laminated silts with varying degrees of Total Organic Carbon (TOC) (Fig. 8) [16, 17]. Below is the composition of each layer.

2.4.4.1 Upper Montney

- Porosity 2-8% average 5.4%, Mineralogy: Quartz 39%, Feldspar 12%, Carbonate 21%, Clay 17%, average perm estimated .006 md
- Toc 1.3%, SW 12%

2.4.4.2 Upper Montney Shale

- Porosity 2-6% average 4%, perm at reservoir conditions .001 md; abundant fractures present (Fig. 9)

- Mineralogy: Quartz 40%, Feldspar 12%, Carbonate 22%, Clay 21%
- TOC 3.2%; SW 13%

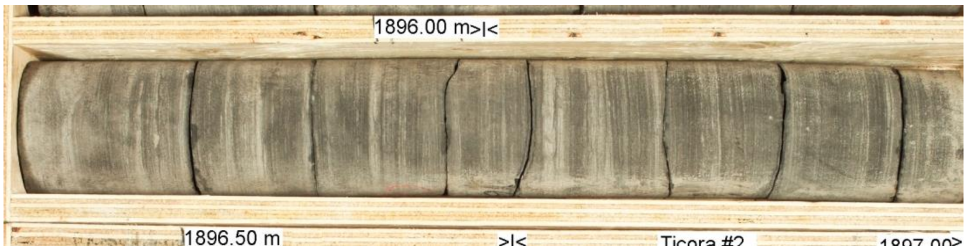


Fig. 9- Upper Montney core sample

2.4.4.3 Middle Montney

- (very little data), Porosity 2-4%, average 2%

2.4.4.4 Lower Montney

- 4-6%, average 5%, perm at reservoir conditions .005 (Fig. 10)
- Mineralogy: Quartz 44%, Feldspar 11%, Carbonate 8%, Clay 27%
- TOC 2.3%; SW 11%

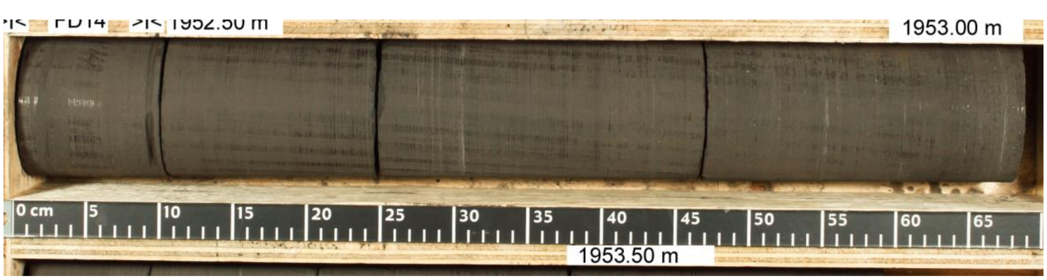


Fig. 10-Lower Montney core sample

2.4.5 Comparison of Montney to Other Shale Plays in North America

Several shale plays are distributed in different places in North America as is shown in Fig. 11. In the U.S from the West Coast to the Northeast, 19 geological basins have shale gas resources. The most important productive formations are the Barnett Shale in the Fort Worth Basin, the Lewis Shale in the San Juan Basin, the Antrim Shale in the Michigan Basin, the Marcellus Shale and others in the Appalachian Basin, and the New Albany Shale in the Illinois Basin. Also in Canada, the productive shale formations are found in the Western Canadian Sedimentary Basin underlying 1,400,000 square kilometers (540,000 sq. mi) of Western Canada including southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia and the southwest corner of the Northwest Territories [18]. The Montney and Horn River basin formations are the main gas shale resources in the Western Canadian Sedimentary Basin. The Montney shale gas play ranks among one of the best natural gas plays in North America. Shale thickness is higher than that found in the Barnett, Haynesville, Marcellus and Horn River basins. Moreover after the Marcellus (1500 Tcf), the Montney play has the second rank in total original gas in place for play (900 Tcf).

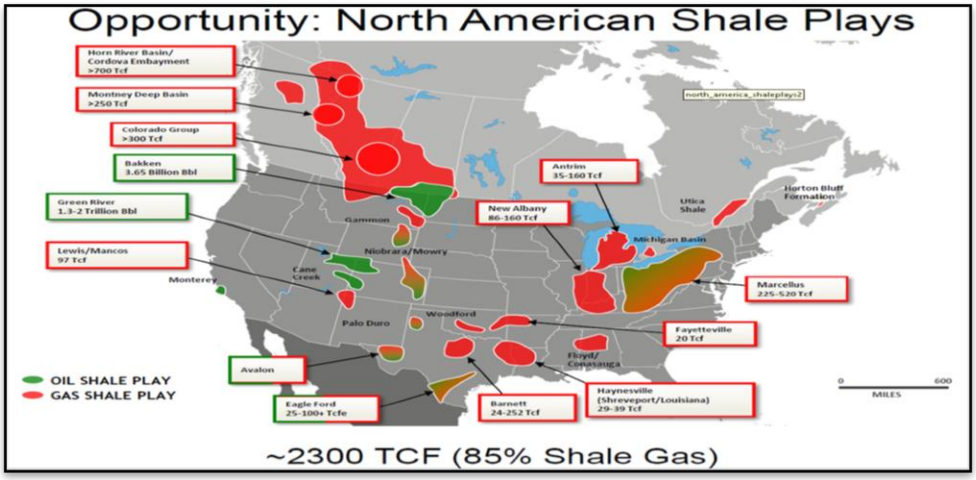


Fig. 11- North American shale plays

The recovery factor in the Montney is the same as in other big plays (20-40%); however, the Montney average estimated ultimate recovery (2.0-6.0 bcf/well) is greater than the Barnett and the Marcellus plays (Table 5). These numbers come from various third-party sources, such as exploration and production companies that release information as part of their public reporting annually. Fig. 12 is a bar chart comparing Montney properties with other main plays. Montney permeability (nd), porosity and pressure gradient (psi/ft.) are higher than other large plays such as the Barnett, Marcellus and Ft St John.

Table 5- Comparison of Montney and other top shale plays in North America

	Barnett	Haynesville	Marcellus	Horn River	Montney
Depth (ft.)	6,500-9,000	10,500-13,500	3,000-8,500	6,500-13,000	5,000-10,000
Thickness of Shale (ft.)	328-1,640	656-984	164-820	984-1,968	984-1,640
Total Organic Content (%)	3.0-7.0	3.0-5.0	3.0-12.0	3.0-10.0	2.5-6.0
Total Original Gas in Place for Play (Tcf)	327	717	1500	500	900
Original Gas in Place (bcf/section)	50-200	150-250	50-150	130-320	60-150
Recovery Factor (%)	20-40	20-40	20-40	20-40	20-40
Estimated Ultimate Recovery (bcf/well)	1.0-4.0	4.5-8.5	2.2-4.1	3.0-9.0	2.0-6.0

However, the Haysville porosity, depth, pressure and EUR are greater than the Montney porosity, depth, pressure and EUR, but the Montney still has a higher total organic content that highlights it as a great play.

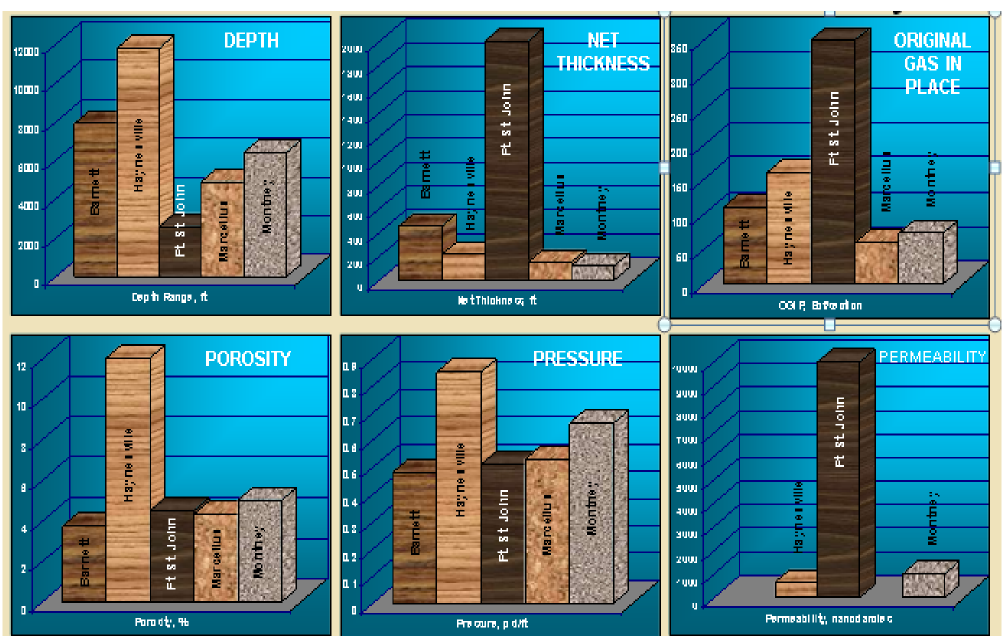


Fig. 12- Shale plays properties

2.4.6 Future of Montney Play

Horizontal drilling technology and hydraulic fracturing techniques that may take several days are expensive in shale gas reservoirs. ″A horizontal well in the Montney Formation will usually cost approximately five to eight million dollars. In the Horn River Basin, a horizontal well costs up to 10 million dollars. Horizontal wells in the Utica Shale are expected to cost 5 to 9 million dollars. Vertical wells targeting biogenic shale gas, like the Colorado Shale, are far less expensive: the resource is shallow and the wells cost less than $350,000 each". [19]

Despite the high cost of horizontal wells in the Montney area, it has the potential to become one of the largest gas producing formations in Canada over the next ten years. Shale transactions in the Montney between 2008 and 2011 total 9.6 (US$ bn) which is the highest after the Marcellus shale play shown in Fig. 13.

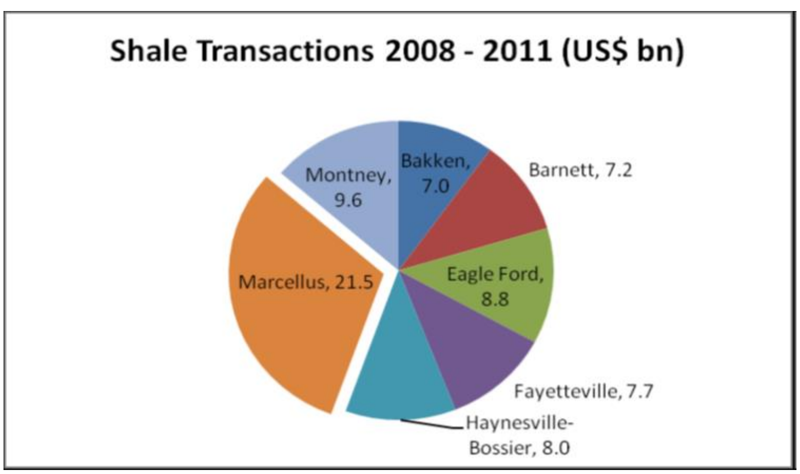


Fig. 13- Large plays shale transactions 2008-2011

More than 20 companies are significant land holders in the area of this study as shon by Fig. 14. Among them Progress, with 2,240,886 net acres, is the largest land holder; however, Encana with 372 wells has the most existing wells. Companies invest in the area because of the high estimate of gas in place (900 Tcf), the repeatability and scability of development drilling, the proximity to west coast and asian markets, low breakeven cost, high rate of return, short payback period, low popoulation density and the limited enviromental footprint. [19]

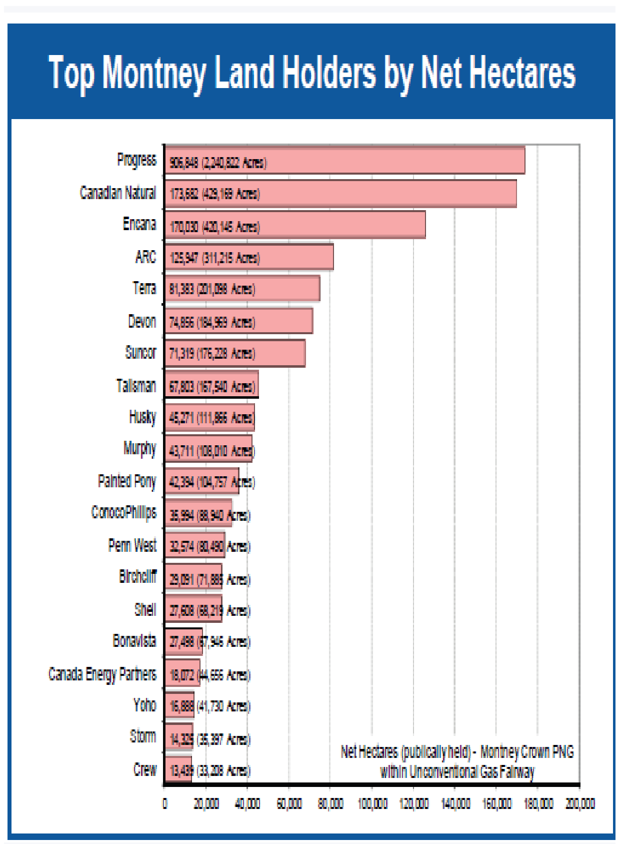


Fig. 14- Top Montney landholders by net hectares

The Montney formation is one of the major economically viable formations in Canada that will attract more and more industrial attention in the near future (Table 6). Knowing the exact parameters to optimize well performance will be a key purpose in this research.

Table 6- Operator companies and number of their wells in Montney formation

Operator	Well count
ECA	372
SHELL	246
ARC	221
MURPHY	185
TALISMAN	112
PRQ	111
TOURMALINE	79
CNRL	46
CREW	42
PAINTED PONY	26
CANBRIAM	19
PENGROWTH	16
STORM	7
PETROBAKKEN	6
ADURO	6
BONAVISTA	6
SUNCOR	5
CROCOTTA	4
DEVON	4
PARAMOUNT	3
UGR	3
YOHO	2
TAMARACK	2
CPC	2
CEQUENCE	1
ARTEK	1
BLACK SWAN	1
PENNWEST	1
TERRA	1

3. THE QUESTION AND OBJECTIVES

3.1 Question and Purpose of Study

Conventional gas resources have been declining over the past few years and expected to continue to decline in the future. Therefore, exploration has shifted to unconventional resources as a consequence. During the past few years, technology improvements have overcome some development challenges they had in unconventional plays and these plays are becoming one of the significant opportunities for worldwide energy supply. In this section, we define two important questions about the Montney unconventional resource and try to answer them in the next chapters.

3.2 Primary Question

In this study our **primary question** is :

- How much do individual completion parameters (Fluid volumes, sand volumes, #frac stages , perf clusterper stage) influence production in complex shale/tight gas formations utilizing horizontal wells?

  The **secondary question** is :

- Can we quantify the impact of fracturing parametrs on production uing only large datasets of public domain information without using in-depth reservoir characterization?

3.3 Primary Objective

- Use multi-variate regression to evaluate the above questions on a real world data set (Montney formation BC, Canada)

3.4 Secondary Objective

- Can we use these tools and results to optimize future completions?

In this research, we study a data set from the Montney unconventional gas formation (Fig. 15) in British Columbia, Canada. This formation has a huge production rate potential. An average well in the Montney shale gas in British Columbia will produce 85,000 to 140, 000 cubic meters per day (m3/d), or 3 to 5 million cubic feet per day (MMcf/d), on startup. In comparison, the average Canadian conventional natural gas well drilled and put on production in 2007 had initial production of approximately 5,700 m3/d (0.2 MMcf/d). [20]

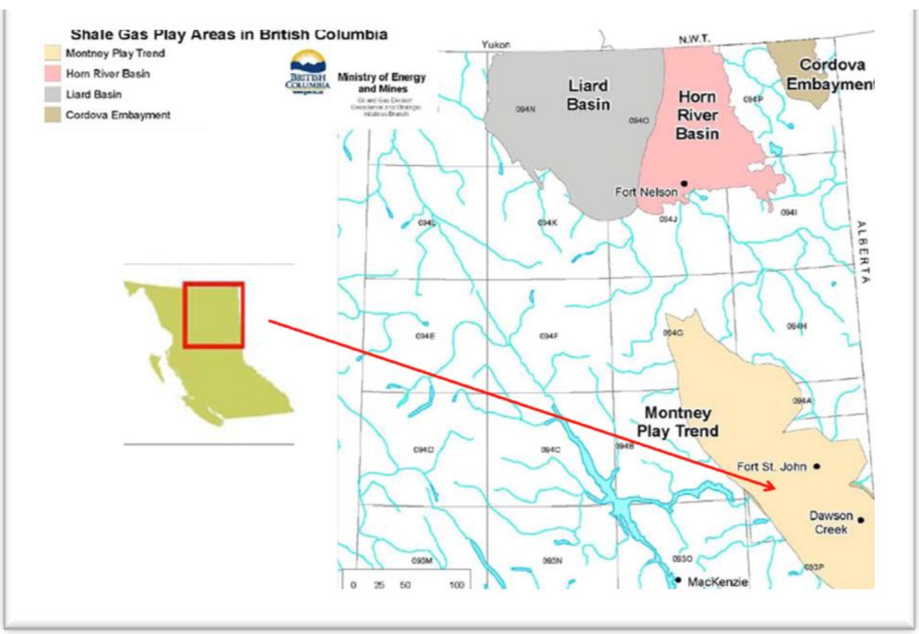


Fig. 15- Montney play map [20]

4. PROCEDURE AND METHOD

4.1 Overview –Concepts

4.1.1 Multivariate Regression vs. 2-D Regression

In this research, first we try to find out the relationship between the gas rate and completion parameters with 2-D regression analysis. Using 2-D regression shows little correlation between B1 (well performance) and any single completion parameter. Details are presented in the next chapter.

After trying 2D regression, we tried multivariate regression, which includes multiple independent variables such as sand volume, fluid volume, lateral length, FS and PC in a single model rather than just one variable. 2-D regression did not reveal any relation between well performance and FS. However, multivariate regression demonstrates a strong correlation between best twelve-months of production (B12) and completions attributes such as FS, as well as number of perforation clusters per stage (PC).

4.1.2 Type Curve Example

After studying multivariate analysis as a tool to understand the relationship between well performance and completion parameters, we generated nineteen regional type curves. The type curve of each region is the average of decline curves of all the wells in the area. We built type curves to use as an input for economic analysis.

4.1.3 Cost Model Example

After creating the regional type curves, we built a cost model for each area in order to determine our average drilling cost and completion cost in each. Next, we used those costs as inputs for economic analysis. The output of the software includes rate of return, PV_{10} and payout. Using these data allow us to make a map of economic results.

4.2 Compile and Review Data

4.2.1 Tables

To develop a methodology and predict well performance in UG, we chose the Montney formation as a case study for application of the proposed procedure. We populated a Montney resources database from the IHS energy document website (public domain) to evaluate relationships among performance indicators (B12 and EUR) and completion parameters. To achieve our goal, we reviewed completion reports for 468 wells, which is approximately one third of the existing wells. We reviewed individual fracture stages to check whether multiple fracture fluid systems were used in a single well. In this study, our focus is on the horizontal wells. Therefore, after completing the database for both horizontal and vertical wells, the vertical wells were excluded from the database (43 wells) leaving 425 horizontal wells in the Montney database.

Table 7and Table 8 show the information collected for each well and the various fluid types injected in Montney wells. We did not include injection rate in our regression analysis. However, upon observation of new well performance we believed it should be considered for the future studies in the future.

Table 7- Basic data on a per-well basis

Basic Data on a Per-Well Basis												
										Post-Frac Flowback		
Gross Completed Interval (ft)	Total Frac Stages	Total Poppant (tons)	Total Fluid (bbl)	Primary Frac Fluid Type	Multiple Fluids (Y/N)	Avg Inj. Rate (bbl/min)	Date of First Frac	Number of perf Intervals	Completion Cost ($)	Flow Rate (Mcf/D)	Flowing Pressure (psia)	Load Recoverd (bbl)

Table 8- Different fluid types

Number of Frac Stage in a Single Well Using These Fluid Type											
Slickwater	Slickwater +CO2	Nitrified Slickwater	Linear Gel	Linear N2 Foam	Linear CO2 Foam	X-linked CO2 foam	Binary foam CO2+N2	Poly CO2	Nitrated Poly CO2	X- Link Oil	Oil CO2 Foam

4.2.2 Maps

To understand the regional distribution of the various properties in our Montney database we made maps showing:

- Wellbore traces and area designations,
- Location of wells in completion database,
- Location of various fracture fluid systems and
- Individual parameters (# frac stages, #Perf cluster per stage, lateral length, fluid volume injected).

All the wells in the database are located in British Columbia. More than 1,000 horizontal and vertical wells have been drilled in British Columbia and Alberta but our research does not include wells located in Alberta. Production (Fig. 16) is dominantly from the Heritage pool of British Columbia. The eastern part of British Columbia Montney play is the Heritage pool, which we divide into smaller logical development areas.

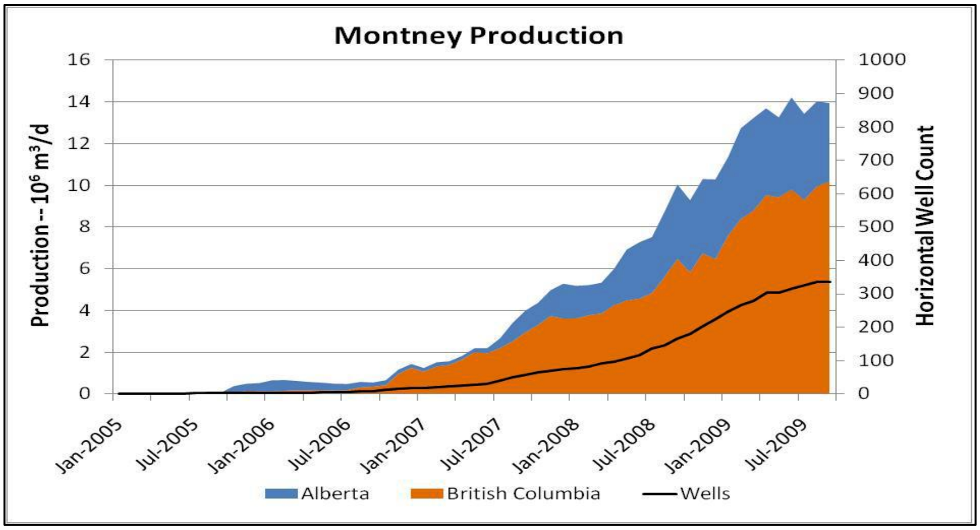


Fig. 16- Montney production and well count in Alberta and BC province

Fig. 17 shows the wellbore traces and area designations of our study. Nineteen grey-shaded areas are our geographic groupings. Wells included in this study are color coded by different colors. The line on the left side of Fig. 17 is the border of Alberta and British Columbia. Fig. 18 shows the location of wells in the completion database. Fig. 19, Fig. 20 and Fig. 21 are the maps of FS, PC and fracture fluid in grey-shaded areas of our study and shown in the next pages.

4.2.2.1 Base Map Showing Wellbore Traces and Area Designations

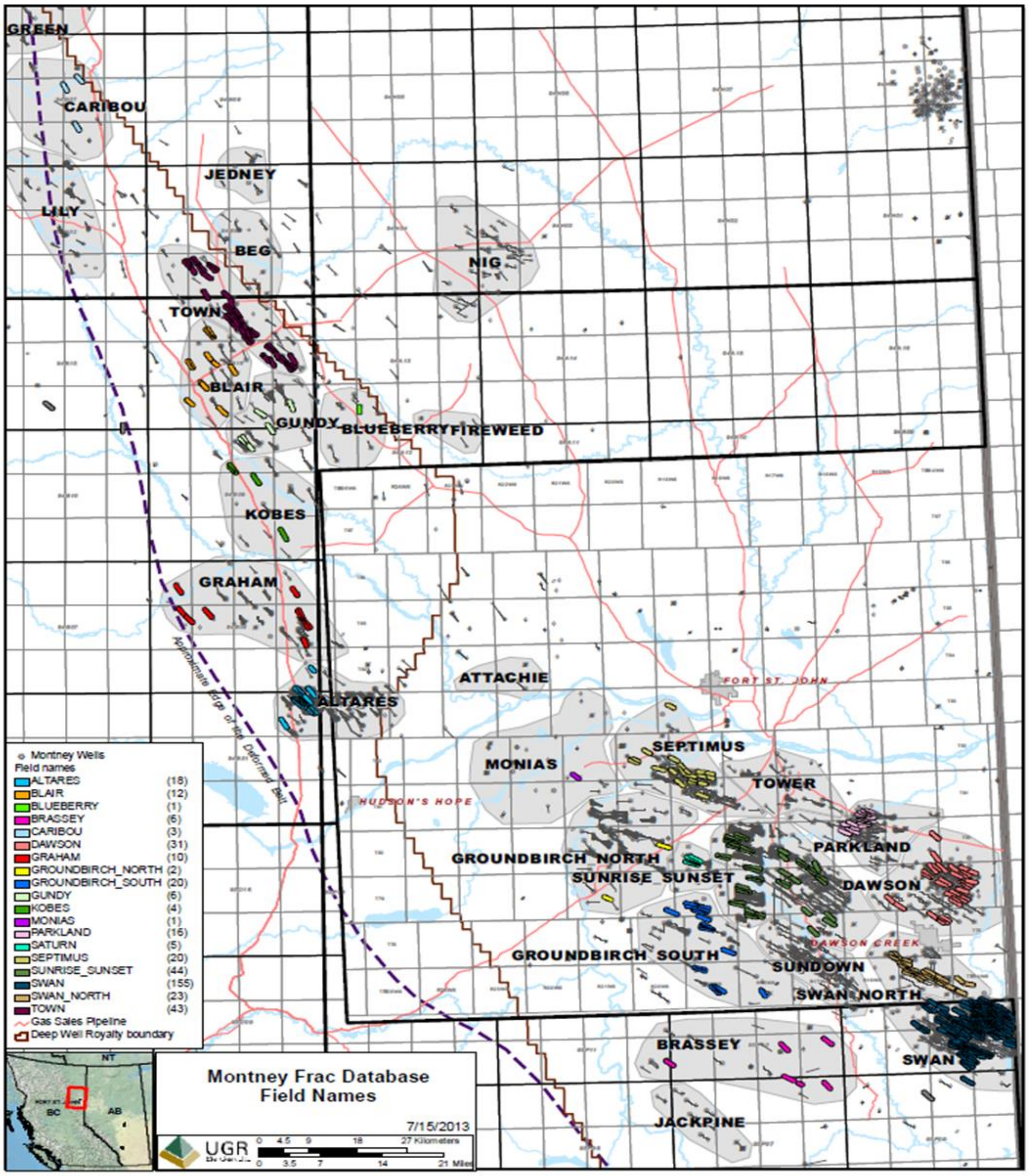


Fig. 17- Base map showing wellbore traces and area designations

4.2.2.2 Map Showing the Location of Wells in the Completion Database

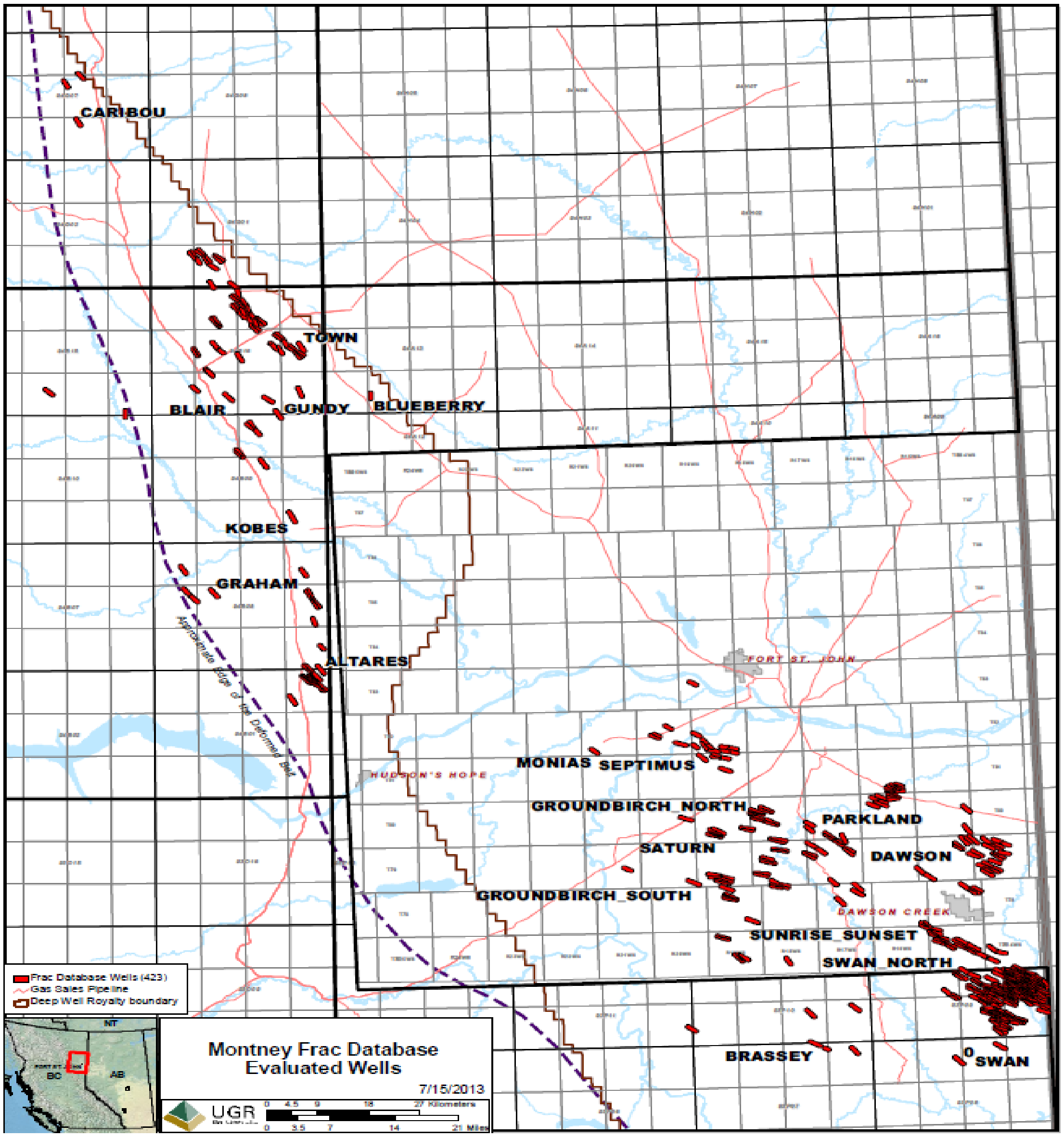


Fig. 18- Map showing the location of wells in the completion database

4.2.2.3 Map Showing Various Fracture Fluid Systems

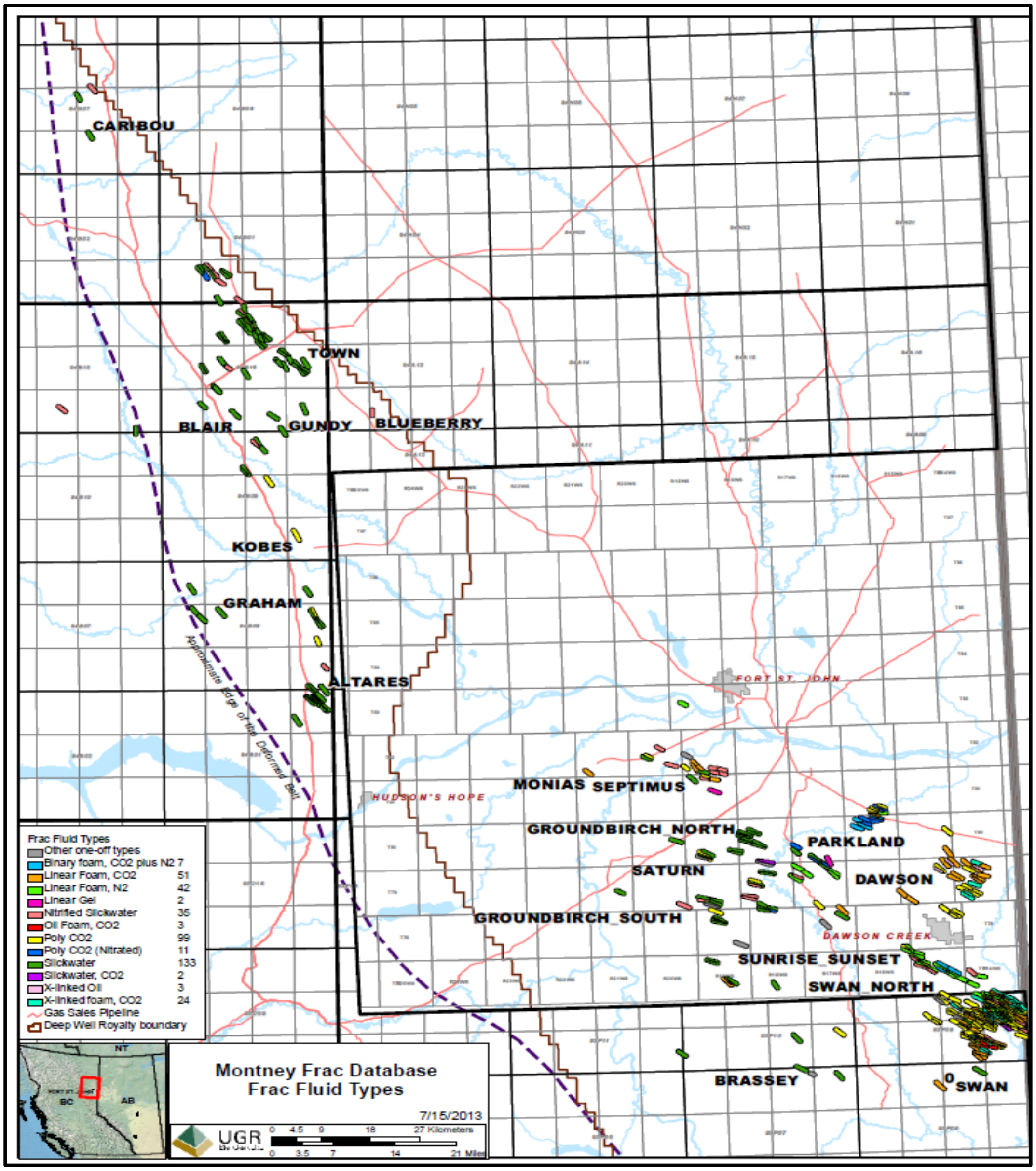


Fig. 19- Map showing various fracture fluid systems

4.2.2.4 Map of Number of Fracture Stages

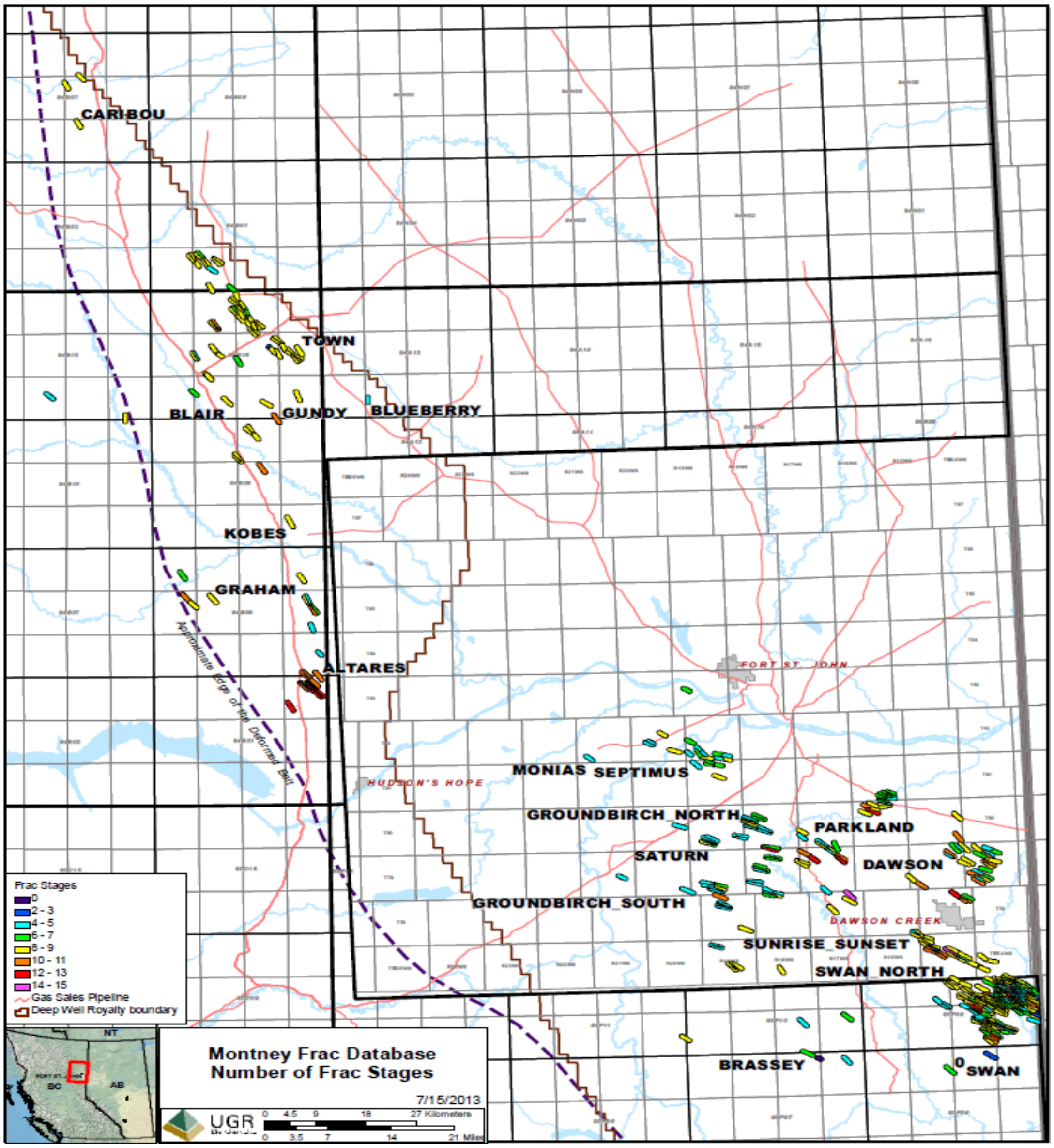


Fig. 20- Map of number of fracture stages

4.2.2.5 Map Number of Perforation Clusters per Stage

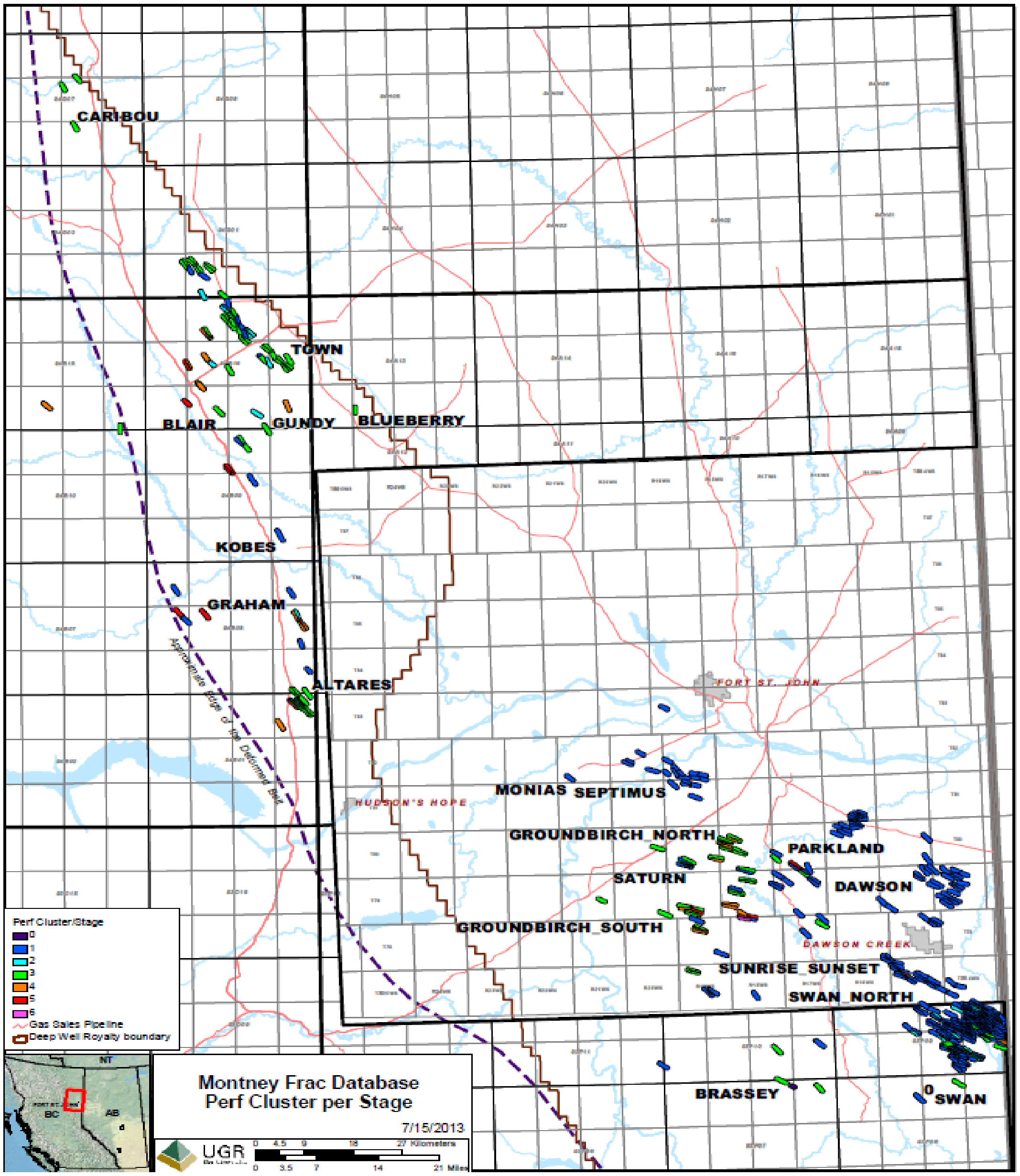


Fig. 21- Map of number of perforation clusters per stage

4.3 Statistical Review in Montney Play Based on our Database

In this section, we illustrate the broad range of numbers for the well performance and the completion parameters in the entire database and for a subset of slickwater wells. Based on our database, the Montney has 26 fields with nine active areas. Moreover, 13 various fluid types are used for fracturing treatments. We discuss all of them in detail later in this chapter. Minimum, maximum and average of several completion parameters (B12 and all individual parameters that were gathered) are shown in Table 9 .

Table 9- Summary of database parameters – entire database

	B1(Mcfed)	B12 (Mcfed)	EUR (Bcf)	LL (m)	FS	PC	Fluid (m3)	Total Sand (tonnes)
Min	392	438	0.1	136	2	1	794	50
Mean	3,839	2,340	6.1	1,448	7.4	1.8	27,551	933
Max	11,949	3,428	28.7	2,795	15	6	266,507	4,745
Count	421	421	421	421	421	421	421	421

As you can see in the above table, the maximum average B12 is 3,428 (Mcfed) which is in the Dawson area. The average lateral length in Dawson is 4,845 ft., which is not the maximum LL in the Montney play, the longest lateral length occurs in Groundbirch-North with length of 2,795 meters. According to Table 10, the average number of fracture stages in slickwater wells is 7.5 close to the max average FS in the entire play of 9. The number of PC in the slickwater wells is almost two times of the average PC in the entire data.

Table 10- Summary of database parameters – slickwater wells- by area

Area	Count	Best Year (Mcf/D)	Completed Lateral Length (ft)	Fracture Stages	Perforation Clusters Per Stage	Fracture Fluid (bbl)	Sand (tons)
Altares	17	2,429	5,577	11.1	3.1	120,089	3,020
Blair	10	2,355	4,526	7.6	3.9	67,160	1,955
Brassey	4	1,228	4,477	5.8	2.5	34,414	1,002
Caribou	1	1,251	4,528	8.0	3.0	67,683	1,694
Graham	8	2,462	5,088	8.5	3.1	79,499	2,152
Groundbirch_North	2	438	4,444	4.5	3.0	26,133	744
Groundbirch_South	14	982	5,356	5.7	3.0	33,791	1,124
Gundy	4	3,670	4,993	9.0	3.3	77,881	2,098
Kobes	2	4,632	4,076	8.0	5.0	89,207	2,372
Saturn	2	2,674	5,274	5.0	3.0	28,625	1,150
Septimus	3	2,562	3,288	6.3	1.0	39,953	920
Sunrise_Sunset	24	2,551	5,723	5.7	3.6	34,729	1,199
Swan	2	2,471	5,435	6.5	2.0	82,776	1,091
Swan_North	1	2,128	5,545	8.0	1.0	6,415	949
Town	33	2,512	4,418	7.9	2.5	67,486	1,819
Total or Average	**127**	**2,311**	**5,001**	**7.5**	**3.0**	**62,829**	**1,742**

Furthermore, for better understanding of completion parameters distribution we plotted the probability plots of them in @Risk. As shown in Fig. 22, the best-fitted distribution of B12 is a Weibull distribution with a mean of 2,344.6 close to the mean B12 of 2,340 in Table 9, with a standard deviation of 1,180, a minimum of 117 and a maximum of 6,030. The rest of the completion parameter probability plots are in appendix A.

The best-fit plot helps us determine the distribution for each independent variable (FS, PC, fluid, sand). When applied to Monte Carlo simulation later in this thesis, we truncate the distribution of each variable coefficient to better match the range of the real data.

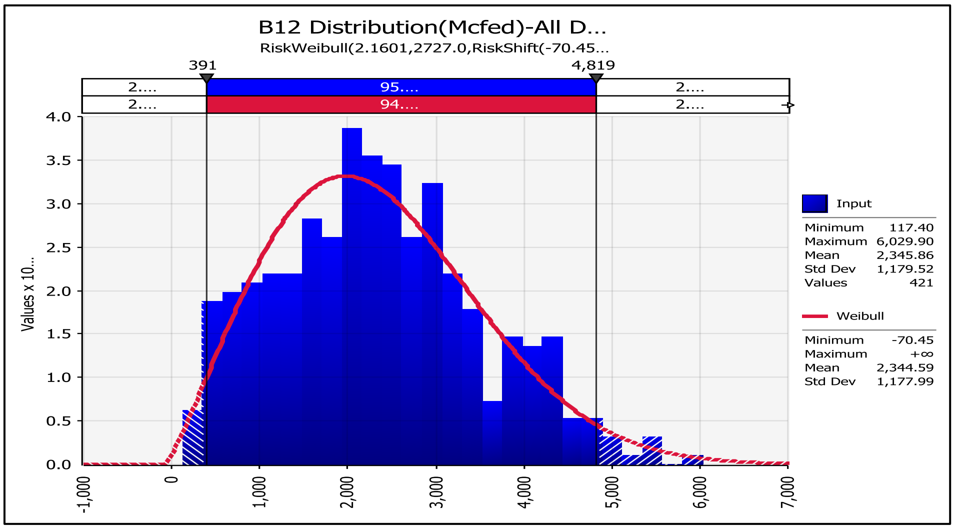
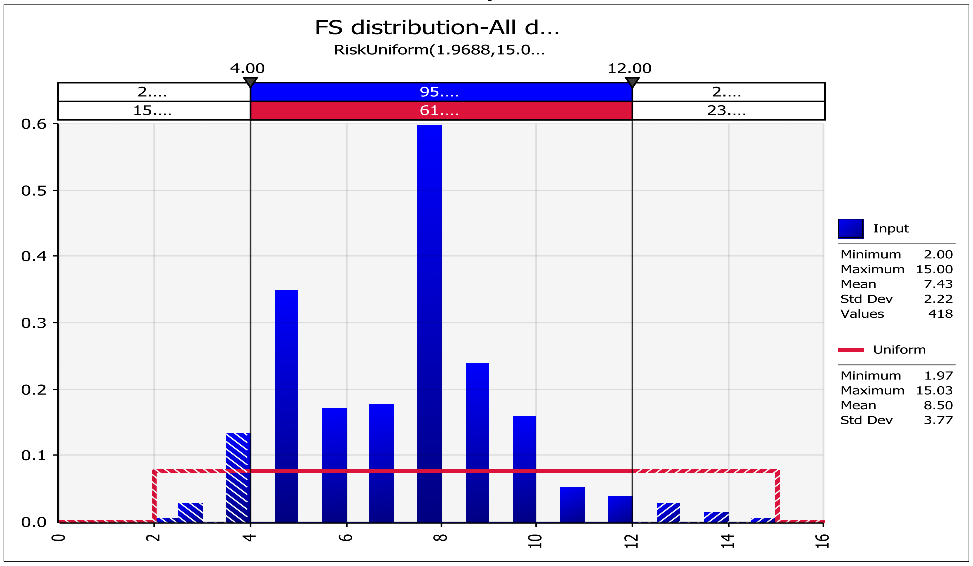


Fig. 22- B12 (Mcfed)-Probability distribution-all data

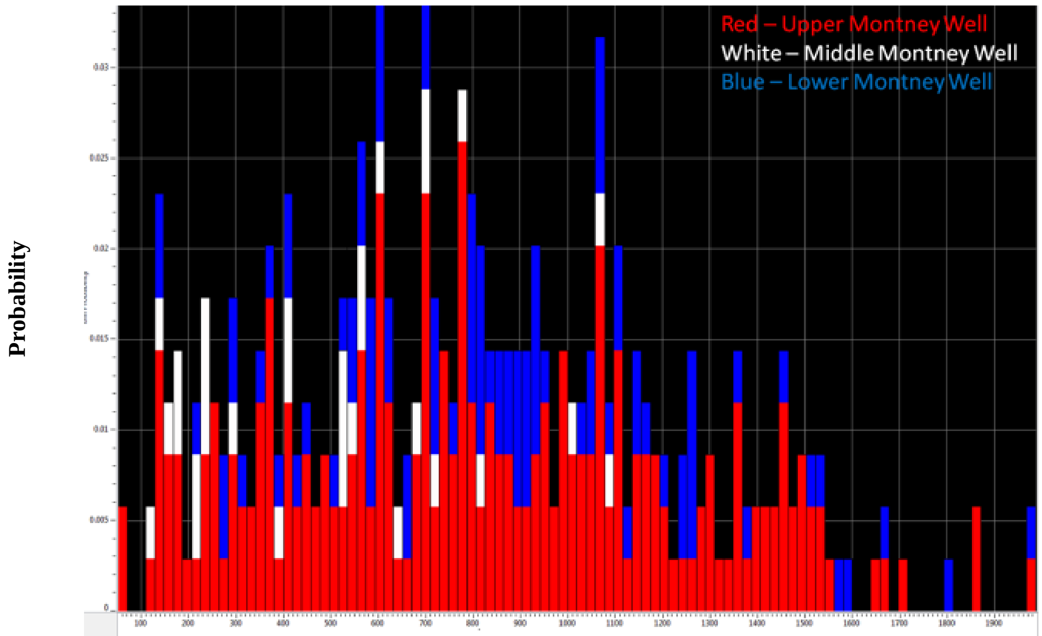
Table 11 is an example of the FS distribution, which is a uniform distribution with an average of 7.4 and a standard deviation of 2.2.

Table 11- FS- Probability distribution-all data



4.3.1 Montney Play Intervals

The Montney formation has three distinct intervals of pay: Upper, Middle, and Lower. The most productive are the Upper and Lower intervals. Ninety percent of wells in the play are in the Upper interval. Currently just 10 percent of wells are located in Lower Montney interval. While most of wells are in the upper interval (as Table 12 shows), the lower interval has almost twice total original gas in place (TGIP) as the Upper and is being actively drilled. Fig. 23 is a histogram of 1-year cumulative production for wells in the Montney zones.



Cumulative one-year production

Fig. 23- 90 Histogram of cumulative one-year production [21]

In this research, we did not group or analyze the data by the Montney zone.

Table 12- TGIP in Lower Montney and Upper Montney (Halliburton)

	Area Acres	Low TGIP-Bcf	Middle TGIP-Bcf	High TGIP-Bcf
After 2500m and Tmax 455ºC cutoffs				
Upper Montney	6,647,258	41,775	114,882	313,315
Lower Montney	6,647,258	80,382	221,052	602,868
Total Montney	6,647,258	122,157	335,934	916,183
		Bcf/section	Bcf/section	Bcf/section

4.3.2 Montney Wells Distribution by Field

Based on the UGR database the 428 horizontal wells are located at 26 fields. The wells are mostly located in six of these fields and the rest of them can be lumped into one group (Table 13). Also, as it shown in Fig. 24, the most wells in our database are in Swan with 166 wells out of 428 (37%). After Swan, Town has the second-most wells in our database. Most wells are located in the east part of the play while the west part is still growing. Some areas in the Montney play are lightly drilled such as Monias with one well or Kobes and Gundy with four and six wells respectively in our database. Our research can help to optimize the performance of future wells in all these fields.

Table 13- Montney well distribution

Area	Count	Percentage
Altares	18	4.24
Blair	12	2.82
Blueberry	1	0.24
Brassey	6	1.41
Caribou	3	0.71
Dawson	31	7.29
Graham	10	2.35
Groundbirch_North	2	0.47
Groundbirch_South	20	4.71
Gundy	6	1.41
Kobes	4	0.94
Monias	1	0.24
Parkland	16	3.76
Saturn	5	1.18
Septimus	20	4.71
Sunrise_Sunset	44	10.35
Swan	156	36.71
Swan_North	23	5.41
Town	47	11.06
Total	425	100.00

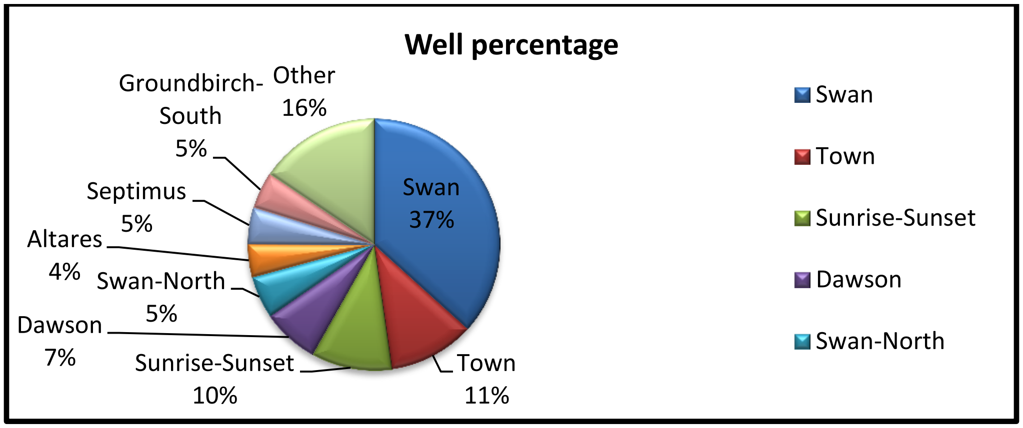


Fig. 24- Distribution of Montney wells in various fields

4.3.3 Montney Fracture Fluid Types

To increase the profitability of shale gas wells, it is common to stimulate by pumping various fractures fluid and create fracture networks. Multi-stage horizontal wells using a large volume of fluid for this purpose is the current technology. Table 14 shows that in the Montney, 13 different fracture fluid types have been used. We consolidate those fluids to seven groups over the 428 wells as shown in Fig. 25. Slickwater and Poly Co2 have been the most popular fluids in the past few years. One hundred thirty four slickwater wells in the Montney have been completed (31%), which is the most common fracture fluid type. After slickwater, Poly CO2 with 23%of the completion has the next highest percentage.

Table 14: Fracture fluid treatment used in Montney wells

Fracture Fluid Type	Number of wells	Percentage
Slickwater	134	31%
Poly CO2	100	23%
Linear Foam, CO2	51	12%
Linear Foam, N2	43	10%
Nitrified Slickwater	35	8%
X-linked foam, CO2	25	6%
Multiple Fluid type	12	3%
Poly CO2 (Nitrated)	10	2%
Binary foam, CO2 plus N2	7	2%
X-linked oil	3	1%
Slickwater, CO2	3	1%
Oil Foam, CO2	3	1%
Linear Gel	2	0.04%
Total	425	100%

As shown in the pie chart, other fluids such as X-linked foam, CO2 and X-linked oil, are occasionally used.

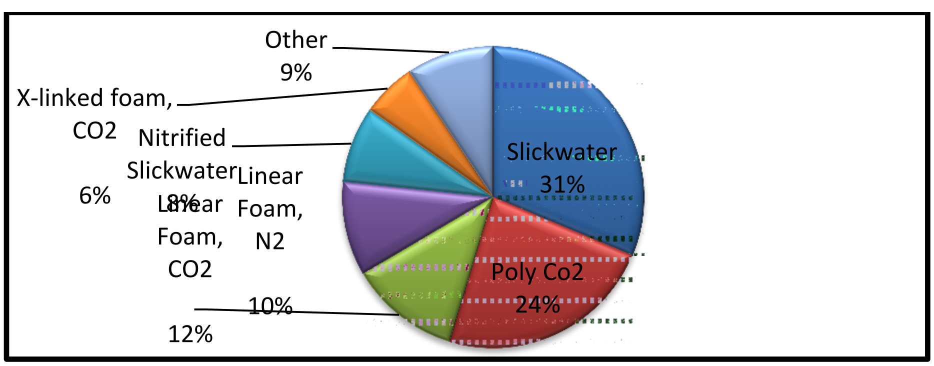


Fig. 25- Distribution of fluid type in Montney

As is presented in Table 15, slickwater fracturing treatment fluids becomes more common after 2009 in our database.

Fig. 26 shows that the number of slickwater, Poly Co2, and other fracture fluid types increased from 2006 to 2009. From 2009 until 2012, the percentage of slickwater increased and the application of the other two types decreased. Although Poly CO2 is an excellent fluid to improve production, it is used in only a few specific areas such as Swan and Dawson. Slickwater fluid is the most common fracture fluid used. There are not many recent wells in our database, therefore the total number of wells is reduced in 2012.

Table 15: Slickwater treatment over time

Year	Poly CO2	Slickwater	Other
2006	6	0	8
2007	18	1	25
2008	30	4	44
2009	38	37	84
2010	7	39	31
2011	0	46	0
2012	0	7	0

Swan has the most number of wells in the database and surprisingly has the least slickwater treatments with 1.2%. The rest of treatments in Swan are Poly Co2 with 41.6% of the total. Town, with 43 wells, has the highest number of slickwater wells in the play as shown in Table 16. Talisman, Cambarian, Progress and Painted Pony are the companies that apply slickwater treatment most often.

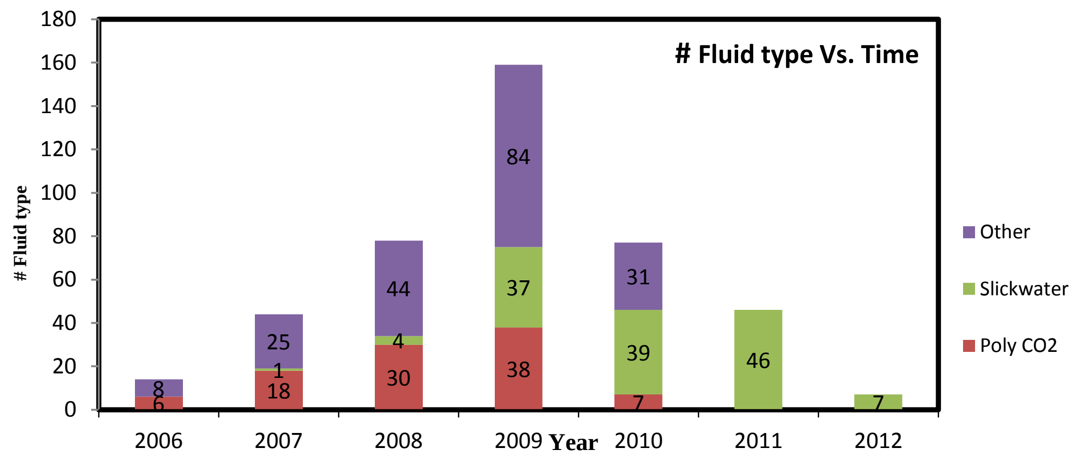


Fig. 26- Slickwater treatment increased over past few years

Table 16: Percentage of completion using

Field	Count	# Slick water	Percentage %	Operator	Frequent Fluid type in this field
Altares	23	20	86.96	**TALISMAN , CANBARIAN**	
Town	43	37	86.05	**PROGRESS ,PAINTED PONY**	
Sunset	28	20	71.43	**Shell ,Huron**	**(Nitrified Slickwater) , (Linear Foam, CO2)**
Groundbirch	15	10	66.67	**SHELL**	
Sunrise	29	5	17.24	**HURON,ECA ,TOURMALINE**	**(Linear Foam, N2)**
Septimus	15	2	13.33	**CREW,CNRL**	
Swan	166	2	1.20	**ECA ,MURRPY**	**(Poly CO2),(Linear Foam, N2) , (Linear Foam, CO2)**
Dawson	29	0	0.00	**ARC**	**(Poly CO2), (Linear Foam, CO2) , (X-Linked Foam CO2)**
Parkland	15	0	0.00	**ARC**	**(Poly CO2), (Poly CO2(Nitrated)),(Binary Foam CO2 Plus N2)**

4.4 Regression Analysis

Regression analysis was used in this study to quantify the effect of the independent completion variables on production rate. Correspondingly, it provides a best-fit equation line through the data points and determines a trend in the data. This trend is useful to select the best completion method to improve well productivity. In addition, regression analysis helps us to understand incremental changes to B12 as individual completion parameters are altered.

4.4.1 2-D Regression Analysis

To define the relationship of completion attributes versus well performance, the completion parameters were studied using bi-variate cross plots. This method was used first for the entire database and then grouped by field and fracture fluid type. The graphs listed below have been plotted for all data and again for the individual 26 fields and 13 fracture fluid types.

- B12 Vs. FS color code by perforation clusters
- B12 per FS Vs. FS color code by perforation clusters
- B1 Vs. FS color code by perforation clusters
- B1 per FS Vs. FS color code by perforation clusters
- B12 Vs. FS color code by perforation clusters
- B12 per FS Vs. FS color code by perforation clusters
- B12 Vs. LL color code by perforation clusters
- B12per FS Vs. LL color code by perforation clusters
- B1 Vs. LL color code by perforation clusters

- B1 per FS Vs. LL color code by perforation clusters
- B12 Vs. LL color code by perforation clusters
- B12 per FS Vs. LL color code by perforation clusters

Also these figures also plotted for all data base:

- B12 Vs. FS color code by fracture fluid type
- B12 per FS Vs. FS color code by fracture fluid type
- B1 Vs. FS color code by fracture fluid type
- B1 per FS Vs. FS color code by fracture fluid type
- B12 Vs. LL color code by fracture fluid type
- B12 per FS Vs. LL color code by fracture fluid type
- B1 Vs. LL color code by fracture fluid type
- B1 per FS Vs. LL color code by fracture fluid type
- B12 Vs. LL color code by FS
- B12 per FS Vs. LL color code by FS
- B1 Vs. LL color code by FS
- B1 per FS Vs. LL color code by FS

Several figures were plotted and none of them showed a strong correlation between production gas rate and completion parameters (LL, FS, and PC).

As shown by Fig. 27, using 2-D regression shows little correlation between B1 (well performance) and lateral length (one of completing parameters). The R squared of 0.009 is small, which indicates a weak or no correlation between B1 and LL.

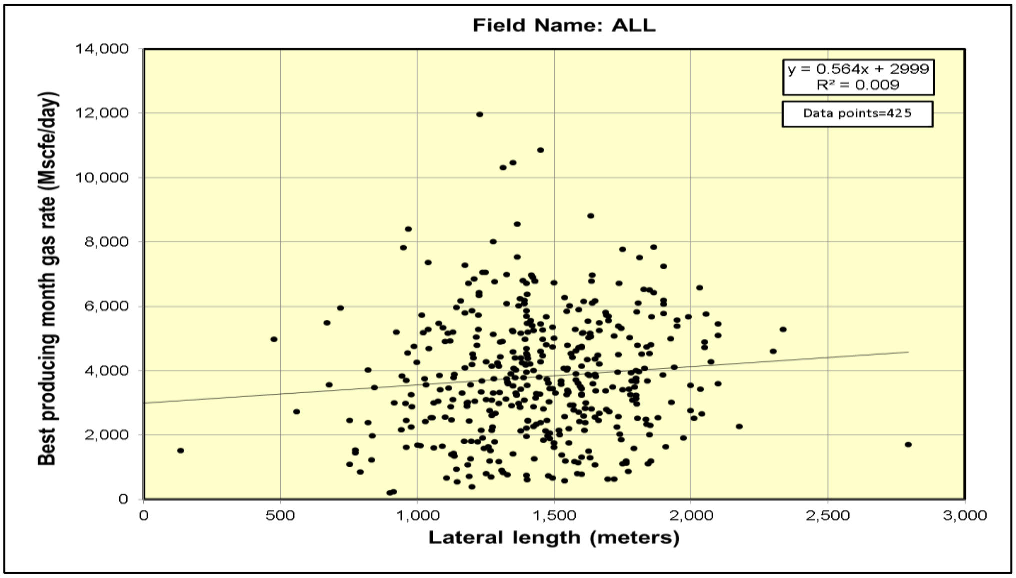


Fig. 27-2-D regression B1 vs. LL showing little correlation

In Fig. 28 shows a slightly improved trend by limiting the data to the slickwater wells. But still the FS and B12 still have a weak correlation.

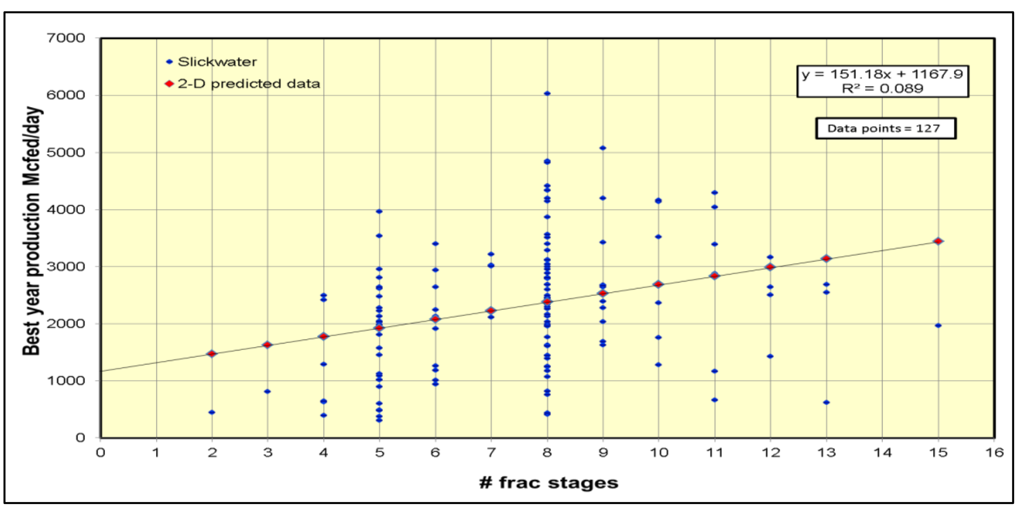


Fig. 28 - B12 vs. #FS (slickwater data only)

Fig. 29 illustrates the estimated ultimate gas production vs. lateral length, color coded by the number of fracture stages for the Swan field. The R squared is small and even the naked eye cannot see any trend. Unexpectedly the longest lateral length well (2,074m with EUR equal 4.3Bcfe) in the Swan field is not the best producing well. The well with the best performance has a 16.3 Bcfe EUR and a 1,423 meter lateral length, which is about 600 meters less than the longest well. Moreover, wells with the same lateral length vary in their long-term performance. This graphs shows that lateral length does not have any clear correlation with EUR.

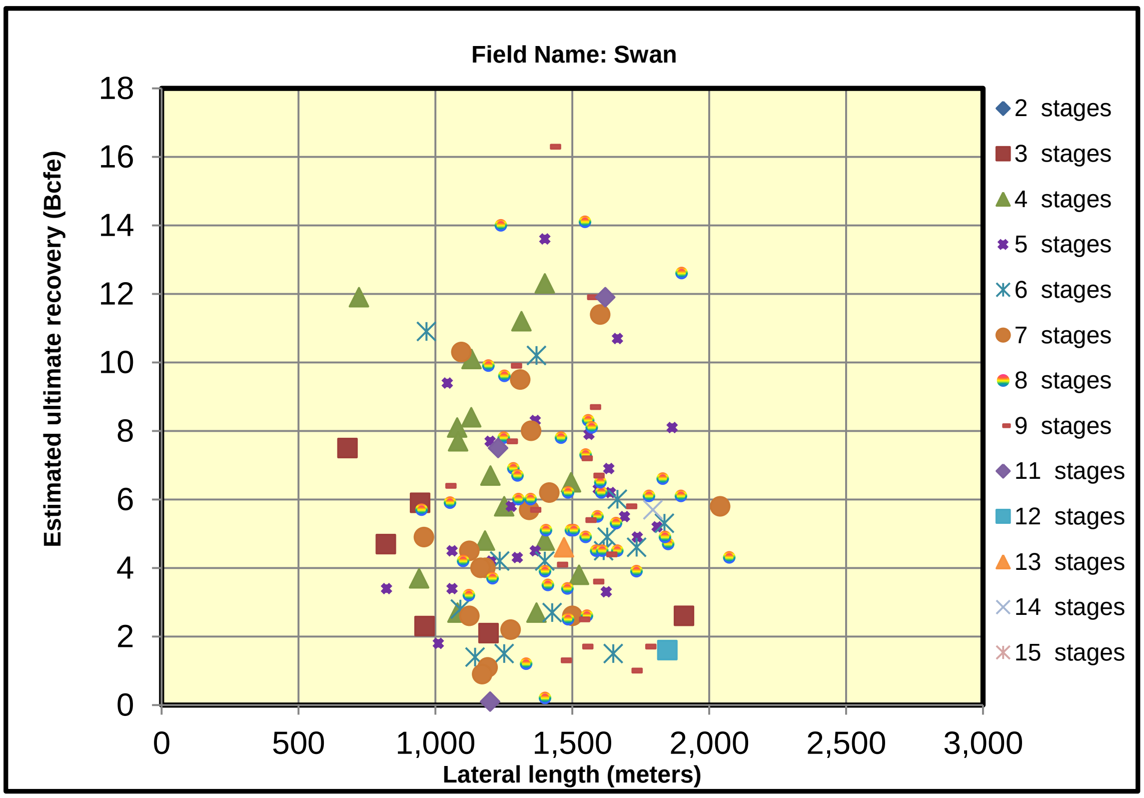


Fig. 29- EUR vs. Lateral length color code by number of FS in Swan field

Fig. 30 shows EUR vs. lateral length for all wells in the Montney database. The EUR of the maximum drilled lateral length (2,795m with 12 stages) is five Bcfe, which is about 4.2 times less than the highest EUR, from a well with a 1,608 meter length and nine fracture stages. In addition, two wells with similar lateral length and fracture stages have dramatically different EUR's ranging from 1.6 to 9 Bcfe. Thus, there is an ineffective relation between EUR and lateral length or EUR and number of fracture stages in both the Swan field data and the entire database.

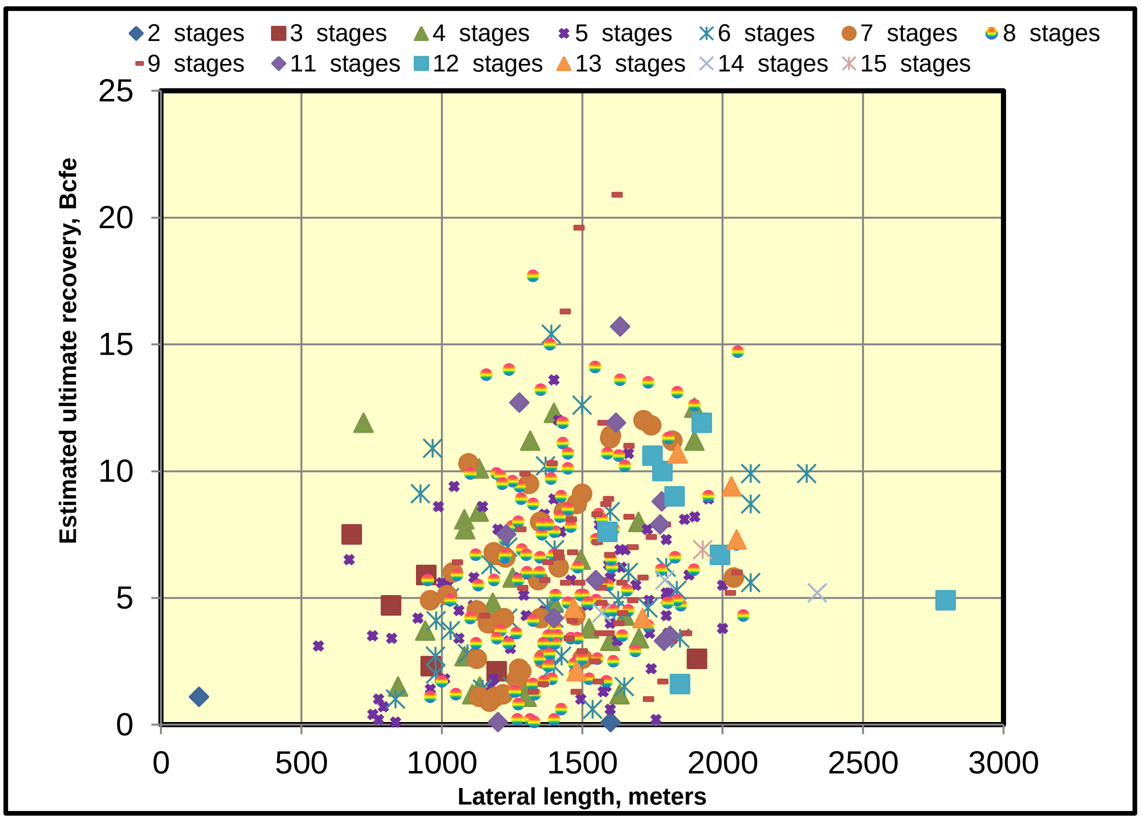


Fig. 30- EUR vs. Lateral length color code by numbers of FS (All data)

The low permeability of unconventional resources reduces the gas diffusion rate. Therefore, a longer time is required to evaluate well performances; as a result, EUR might be considered the best performance indicator among B1, B12, and EUR but EUR is a forecasted number and may be subjective.

The insignificant correlation ($R^2 = 0.0033$) in Fig. 31 apparently strengthens the idea that there is no correlation between the number of fracture stages and EUR based on 156 wells in Swan, the largest Montney field. The best well in this field with 10 fracture stages has an EUR of 23.1 Bcfe while the well with 15 fracture stages has an EUR of only 5.7 Bcfe.

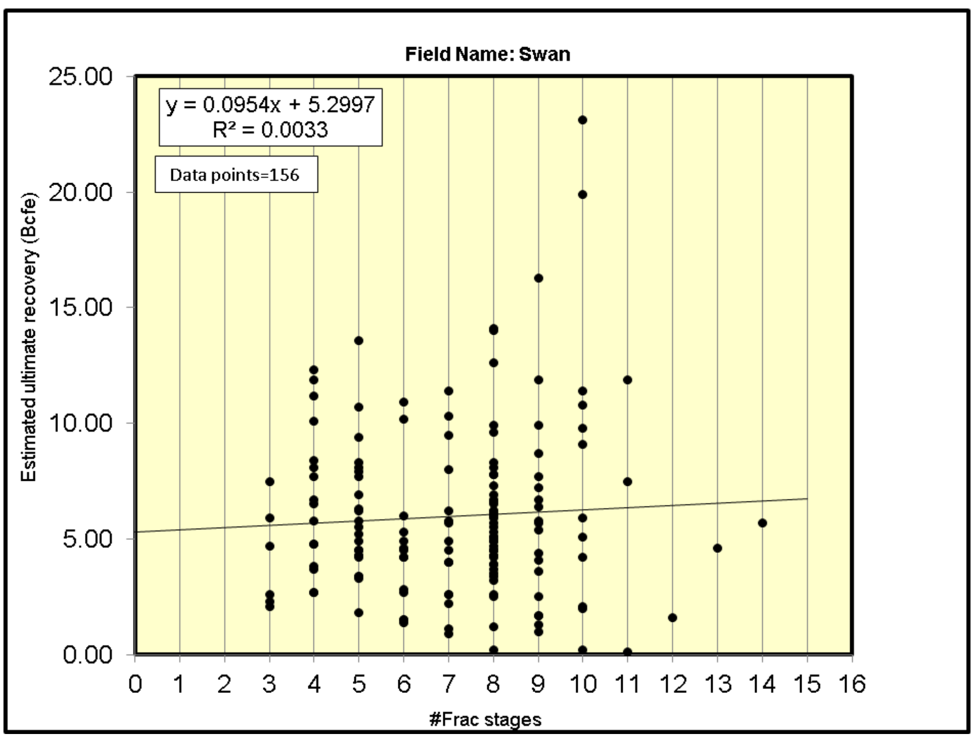


Fig. 31- EUR vs. #Frac Stages in the Swan area

The estimated ultimate recovery (EUR) for wells with 10 fracture stages differs by 22.9 Bcfe (min is 0.2 Bcfe and max 23.1 Bcfe). In addition, the number of fracture stages for average well (EUR between 5 to 10 Bcfe) varies from 2 stages to 11 stages. As shown in Fig. 32 in the Swan area, the best well has an EUR of 23.1 Bcfe and the worst well has an EUR equal to 0.2 Bcfe. Interestingly, both have the 10 fracture stages and one perforation cluster per stage. The well with 4 FS and 4 PC per stage (2.7 Bcfe) has a better production rate compared to the one with 6 FS and 2 PC per stage (1.5 Bcfe), while it has a lower rate compared to the well with 13 FS and one PC per stage (4.6 Bcfe). There is no clear pattern in the data so, the question here is whether more perforation clusters or fracture stages or total perforation intervals (PC*FS) improves the quality of well or not.

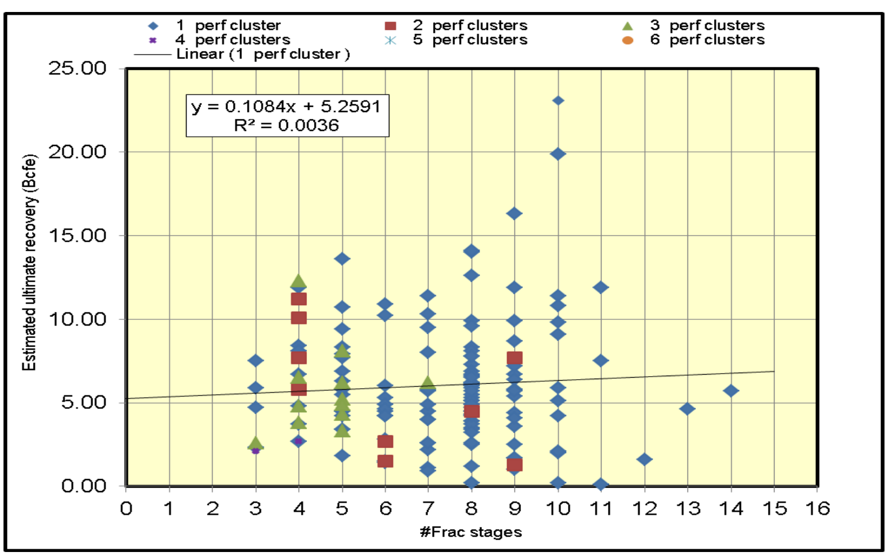


Fig. 32- EUR vs. number of fracture stages color code by perforation cluster per stage in Swan field

Table 17 is the output of 2-D regression for the Swan field. The definitions are as follows:

- **Observations** (166): The number of data pairs in the regression.
- **Adjusted R-Squared** (-0.01): The R Squared is adjusted (reduced) as additional independent variables are added to the model. Adjusted R-Square values can actually be negative by virtue of the adjustment calculation. It is a different measure of goodness of fit than R-Square and considered a better statistic than R-Square for comparing goodness of fit of several competing models.
- **Coefficients**: There are two coefficients in this example, Intercept = 2,345 and FS (number fracture stages) = 9. Those are the coefficients used to describe the regression "Best Fit" line; y = mx + b, where b = Intercept and m = FS coefficient.
- **P-value**: This is the probability that the variable coefficient should be zero, i.e. that the variable should be omitted from the model. The smaller the P-value, the greater the confidence the variable is influencing the dependent variable.
- **Lower/Upper 95%:** These values indicate the lower & upper limits of a variable in a 95% confidence interval. The smaller the P-value, the tighter these limits will be around the coefficient value. For instance, FS is expected to be nine (coefficient), but is more generally expected to be between -71 and 88, with a 95% confidence.

- **Significance F**: This is much like the P-value, but for the model as a whole, not specific to a single variable. This is the probability that the any perceived correlations in the data are due to random chance of the values just happening to be values that appear to correlate when there is no true correlation. The smaller the Significance F, the better. With F = 0.05, there is less than a 1% chance this model tells us nothing about B12. [22]

Table 17- 2-D regression of output summary –Swan field

Regression Statistics								
Multiple R	0.02							
R Square	0.00							
Adjusted R Square	**-0.01**							
Standard Error	1130							
Observations	166							
ANOVA								
	df	SS	MS	**F**	**Significance F**			
Regression	1	59,362	59,362	**0.05**	**0.83**			
Residual	164	209,437,444	1,277,058					
Total	165	209,496,806						
	Coefficients	Standard Error	**t Stat**	**P-value**	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	2,345	302	**7.75**	**0.00**	1,748	2,942	1,748	2,942
FS	9	40	**0.22**	**0.83**	-71	88	-71	88

Table 18- 2-D regression of output summary –all wells

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.159
R Square	0.025
Adjusted R Square	**0.023**
Standard Error	1,165.8
Observations	421.0

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	14,838,540	14,838,540	11	0.001034506
Residual	419	569,489,799	1,359,164		
Total	420	584,328,339			

	Coefficients	*Standard Error*	*t Stat*	***P-value***	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	**1,723.90**	196.62	8.77	**4.6189E-17**	1,337.41	2,110.39	1,337.41	2,110.39
FS	**83.90**	25.39	3.30	**0.0010**	33.99	133.81	33.99	133.81

Table 18 shows a 2-D regression output for the all data. The adjusted R squared is small, which indicates no meaningful relationship between the B12 and completion parameters. Table 19, is summary of 2-D regression coefficient for B12 vs. LL, FS, PC, fracture fluid volume and sand information for all fields in the database. The regression R-squares of major fields (Swan, Town, Dawson, Sunrise, Sunset, and Altares) are much smaller compared to other fields in both B12 and EUR. When many data exist, the statistical indicators show no correlation between B12 and completion parameters. While when few data points exist, there is no statistical meaning even if R squared is high. The same table for lateral length is in appendix A.

Table 19- Equation and R-square of EUR &B12 plots

Area	Count	Completed Lateral Length	Number of Fracture Stages	Perforation Clusters per Stage	Fracture Fluid Volume	Sand
Altares	23	0.04	0.05	0.03	(0.04)	(0.05)
Blair	12	(0.03)	(0.07)	(0.09)	(0.04)	0.21
Blueberry	1	-	-	-	-	-
Brassey	6	0.08	(0.14)	0.14	0.07	(0.16)
Caribou	3	0.99	(0.10)	(0.10)	0.99	(0.99)
Daiber	1	-	-	-	-	-
Dawson	31	0.06	0.01	(0.02)	(0.02)	0.02
Graham	10	(0.11)	(0.11)	(0.03)	0.01	(0.03)
Groundbirch-North	2	-	-	-	-	-
Groundbirch-South	20	0.36	(0.05)	0.11	(0.06)	(0.01)
Gundy	6	0.07	0.61	0.15	0.66	0.15
Kobes	3	(0.22)	(0.66)	0.95	0.86	0.99
Monias	1	-	-	-	-	-
Parkland	16	0.10	0.15	(0.07)	0.14	(0.05)
Saturn	4	(0.15)	(0.16)	(0.06)	0.07	(0.07)
Septimus	20	0.02	0.06	(0.05)	0.38	0.06
Sunset-Sunrise	44	0.18	-	0.23	0.33	0.10
Sundown	3	0.89	(0.05)	0.99	(0.62)	(0.53)
Swan	156	-	-	(0.01)	0.01	(0.01)
Swan-North	23	(0.01)	0.21	(0.04)	0.28	(0.04)
Town	47	0.13	0.11	0.07	0.05	0.02
W-Gundy	2	-	-	-	-	-

In shale resources, the rock properties (permeability and porosity) vary even over a short distance. In addition, petrophysical studies are performed infrequently. Therefore, rock properties are mostly unknown. The 2-D regression results imply that without rock properties, it will be difficult to predict well performance either in any particular area in The Montney.

The injected sand volume, number of fracture stages, number of perforation clusters and lateral length did not show a strong correlation with well performance from the 2-D regression analysis. Separately, the completion parameters had no or weak correlations with production rate, which indicates that no single completion parameter could describe the broad range of Montney production rates.

4.4.2 Multivariate Regression Analysis - Methodology

By combining the completion parameters in a single model and using multivariate regression analysis, we are able to generate a model that can predict production rate from completion parameters (FS, PC, Lateral length). Subsequently, the correlation with production rate is revealed for the parameters that did not show an individual trend on the 2-D regression.

Multivariate regression is the same as the 2-D regression but it has more than one independent variable and can measure the impact of individual variables on the model in the presence of the other variables. We chose five important independent variables out of 13 completion parameters, and combined them in to a single model as shown in Equation 1.

$$B12=b0+b1\times FS+b2\times PC+b3\times LL+b4\times Fluid+b5\times Sand \quad \text{……………………… Equation 1}$$

This is a linear model. The output of the multivariate regression has a similar type of output as the 2-D regression model (Table 18). As you can see, the five variable model is only slightly better at predicting B12 than the 2-D regression model (adjusted R squared is 0.025 compared to 0.023) but individual completion parameter influences begin to emerge. In Table 20, the PC/stage coefficient indicates that adding one perforation cluster per stage will add 104 Mcf/day (3691m^3/day) to B12. When the standard deviation is high compared to the coefficient values, it implies a high level of uncertainty exists and result in a p-value closer to one than zero.

Table 20- Multivariate regression output-all wells

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.192
R Square	0.037
Adjusted R Square	**0.025**
Standard Error	1,164.4
Observations	421.0

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	5	21,646,103	4,329,221	3	0.007684965
Residual	415	562,682,236	1,355,861		
Total	420	584,328,339			

	Coefficients	*Standard Error*	*t Stat*	***P-value***	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	**1,243.44**	357.62	3.48	**0.0006**	540.47	1,946.42	540.47	1,946.42
LL	**0.07**	0.06	1.12	**0.2648**	(0.05)	0.19	(0.05)	0.19
FS	**91.60**	33.62	2.72	**0.0067**	25.51	157.68	25.51	157.68
PC/Stage	**104.38**	78.05	1.34	**0.1819**	(49.05)	257.81	(49.05)	257.81
Fluid	**(0.00)**	0.00	(0.84)	**0.4036**	(0.01)	0.00	(0.01)	0.00
Sand	**(0.17)**	2.18	(0.08)	**0.9367**	(4.46)	4.11	(4.46)	4.11

In addition to completion parameters, reservoir properties and fracture fluid type have a significant impact on the B12. Since we do not limit the data to a specific fluid type in Table 20 and we do not incorporate reservoir properties the model does not match the scatter in the data very well. Therefore, we limited the data to the 127 wells using slickwater as their fracture fluid, the most common fluid type in overall database. As shown by Table 21, the adjusted R squared improved to 0.1 indicating a better match of the data. Considering the FS variable, adding one fracture stage will add, on average, 203 Mcf/day (6,246 m^3 /day) to B12. The P-values in Table 21 decrease compared to

Table 20, which indicates the completion parameter uncertainties are reduced in Table 21. For example in Table 21, the “Upper 95% “and “Lower 95%” of lateral length vary from 61 to 346 Mcf/day for 95%, which indicate adding one foot to lateral length will add, on average and with enough data, 203 Mcf/day/well to B12 but it may vary between 61 to 346.

Table 21- Output summary-slickwater wells

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.369
R Square	0.136
Adjusted R Square	**0.101**
Standard Error	1,110.7
Observations	127.0

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	5	23,547,631	4,709,526	4	0.003021082
Residual	121	149,260,581	1,233,559		
Total	126	172,808,212			

	Coefficients	*Standard Error*	*t Stat*	***P-value***	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	**413.58**	646.28	0.64	**0.5234**	(865.89)	1,693.06	(865.89)	1,693.06
LL	**(0.04)**	0.10	(0.42)	**0.6732**	(0.23)	0.15	(0.23)	0.15
FS	**203.48**	71.89	2.83	**0.0054**	61.15	345.81	61.15	345.81
PC/Stage	**238.34**	105.64	2.26	**0.0259**	29.20	447.48	29.20	447.48
Fluid	**(0.03)**	0.03	(0.84)	**0.4041**	(0.09)	0.03	(0.09)	0.03
Sand	**0.57**	2.64	0.21	**0.8307**	(4.66)	5.79	(4.66)	5.79

In Table 21, only FS and PC have the positive “Upper 95% “and “Lower 95%” values for the coefficient. They also have lower p-values compared to other the variables which shows more certainty that an increase in these variables will consistently increase B12. A negative coefficient for completed lateral length and injected fluid imply that if the completed lateral length or injected fluid increases, the B12 will decreases, which does not seems logical. However, with the statistical interpretation according to Table 21, more lateral length, fluid and sand may make better wells, but their influence is likely minimal compared to the impact of more fracture stages and more perforation clusters.

We next regressed on a model when the intercept was set to zero for the 127-slickwater wells to impose the condition when there is no completion, the production will be zero. As Table 22 shows, the adjusted R squared will improved significantly. However, the variable coefficients did not change much by forcing the intercept to be zero.

Table 22- Multivariate regression output – slickwater Wells, intercept = 0

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.907
R Square	0.822
Adjusted R Square	**0.808**
Standard Error	1,108.0
Observations	127.0

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	5	690,740,669	138,148,134	113	8.66112E-44
Residual	122	149,765,765	1,227,588		
Total	127	840,506,434			

	Coefficients	*Standard Error*	*t Stat*	***P-value***	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	**0**	#N/A	#N/A	**#N/A**	#N/A	#N/A	#N/A	#N/A
LL	**(0.01)**	0.08	(0.11)	**0.9112**	(0.17)	0.16	(0.17)	0.16
FS	**226.27**	62.30	3.63	**0.0004**	102.94	349.60	102.94	349.60
PC/Stage	**245.43**	104.80	2.34	**0.0208**	37.96	452.90	37.96	452.90
Fluid	**(0.03)**	0.03	(1.29)	**0.1988**	(0.09)	0.02	(0.09)	0.02
Sand	**1.34**	2.34	0.57	**0.5676**	(3.29)	5.97	(3.29)	5.97

The line fit plot Fig. 33, which is one of the plots of the multivariate regression analysis generated by Excel, shows the predicted B12 (red dots) and real B12 (blue dots) vs. FS in the same plot. Notice that in the 2-D regression (Fig. 28) all the red dots are on the line and do no mimic the scatter of the data (Fig. 33). However, in the multivariate regression we can see some scatter in the production values of B12 for each value of FS. If the match were perfect, then the red dots would cover the range of blue dots. For each independent variable, we have a line fit plot included in appendix A.

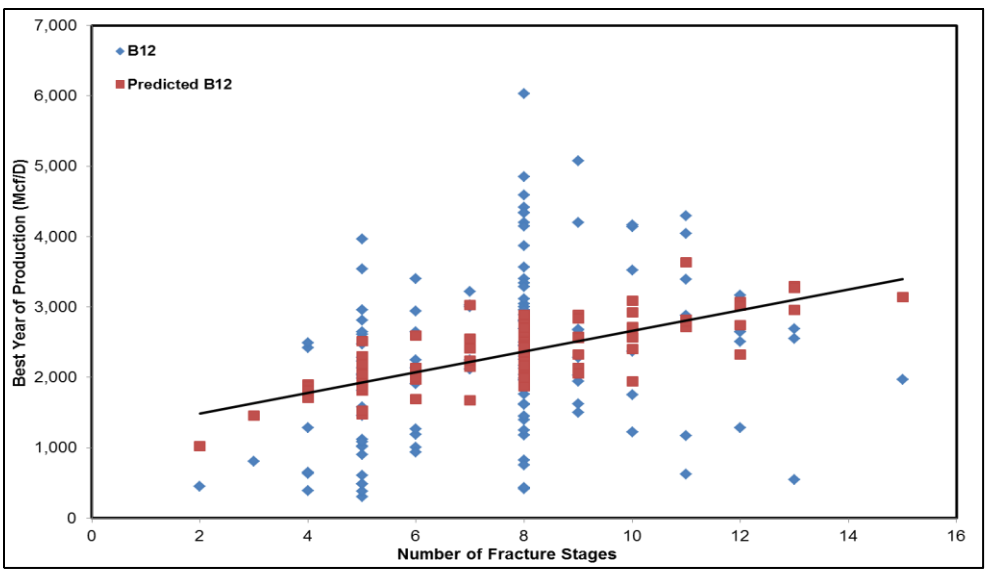


Fig. 33- Multivariate regression graphical output – line fit plot, slickwater wells

A residual plot is another plot in the regression analysis that illustrates the difference between each real and predicted point vs. each independent variable. Ideally, the residual should be a normal distribution with a mean of zero with no discernible trend. In Fig. 34 we see a slight concave trend with negative residuals when FS is near either a maximum or minimum.

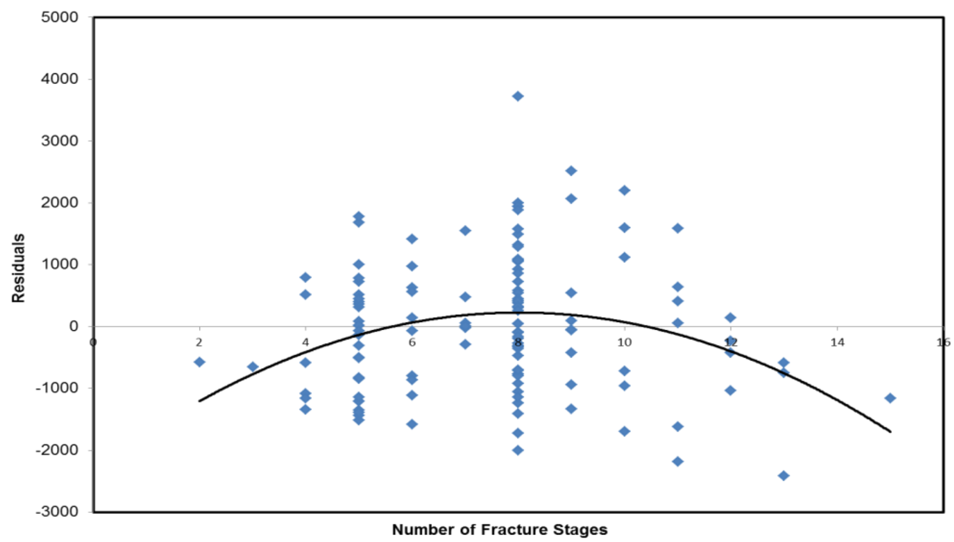


Fig. 34- Multivariate regression graphical output – residual plot, slickwater wells

4.4.3 Application of Multivariate Analysis

We reported the multivariate analysis for these sub-groupings:

1. By fracture fluid type and
2. By geographic area

Grouping by geographic area limits the variation in reservoir properties. Also grouping by both geographic area and fracture fluid types results in individual data sets too small for useful analysis. The slickwater fluid type subgroup is large enough to provide useful dataset.

The four models that we evaluated for the slickwater wells are as follows:

$$B12 = b0 + b1 \times FS + b2 \times PC + b3 \times LL + b4 \times Fluid + b5 \times Sand \quad \text{…...........Equation 2}$$

$$B12 = b0 + b1 \times FS + b2 \times PC + b3 \times LL + b4 \times Fluid \quad \text{……………………....Equation 3}$$

$$B12 = b0 + b1 \times FS + b2 \times PC + b3 \times LL/PI + b4 \times Fluid/PI + b5 \times Sand/PI. \quad \text{Equation 4}$$

$$B12 = b0 + b1 \times FS + b2 \times PC + b3 \times LL/PI + b4 \times Fluid/PI \quad \text{………………...Equation 5}$$

PI is the number of perforation intervals (PI=FS*PC). In models 2 and 4, the sand is excluded because this variable has the weakest impact on the B12 in the slickwater data deck. Table 23 shows the regression results for dataset**s** grouped by fracture fluid type both forcing the intercept to be zero and non-zero. As shown in the zero intercept **cases** the adjusted R squared increases materially, but the coefficient of each variables changes marginally.

Table 23- Comparison of regression results for intercept = zero or computed intercept

Regression Model 1a - Intercept is Computed														
			Model Coefficient (Mcf/d per unit of variable)						Probaility that Coefficient = 0					
Frac Fluid Type	Count	Adj. R^2	Int. (Mcf/d)	LL (ft)	FS	PC	Fluid (bbl)	Sand (tons)	Int.	LL	FS	PC	Fluid	Sand
Linear Foam, N2	41	(0.02)	577	(0.19)	144	(576)	0.05	17.4	86%	48%	24%	59%	59%	57%
POLY Co2	98	(0.02)	2,360	(0.01)	51	268	0.02	(5.5)	2%	97%	62%	34%	62%	43%
Linear Foam, CO2	50	0.10	514	0.26	16	(1,146)	12.64	0.0	84%	30%	91%	42%	76%	43%
Slickwater	127	0.10	521	(0.06)	202	241	(0.00)	0.5	45%	55%	1%	2%	43%	86%
Nitrified Slickwater	35	0.16	(772)	0.42	90	91	0.00	0.7	49%	4%	49%	68%	93%	92%
X-linked foam, CO2	25	0.14	(2,065)	(0.02)	205	(1,303)	(0.08)	48.4	24%	94%	16%	16%	35%	2%
Poly CO2 (Nitrated)	11	0.08	(4,426)	0.53	(682)	-	(0.22)	100.0	71%	66%	26%	0%	81%	0%
Multiple Fluid Types	12	0.43	464	1.08	(379)	(2,012)	0.09	6.4	85%	3%	13%	4%	57%	26%
Regression Model 1a - Intercept = 0														
			Model Coefficient (Mcf/d per unit of variable)						Probaility that Coefficient = 0					
Frac Fluid Type	Count	Adj. R^2	Int. (Mcf/d)	LL/PI (ft)	FS	PC	Fluid/PI (bbl)	Sand/PI (tons)	Int.	LL/PI	FS	PC	Fluid/PI	Sand/PI
Linear Foam, N2	41	0.84	-	(0.18)	144	(519)	0.05	22.2		49%	23%	60%	59%	10%
POLY Co2	98	0.79	-	0.06	180	375	(0.00)	6.2		72%	5%	19%	99%	24%
Linear Foam, CO2	50	0.67	-	0.28	21	(974)	0.02	14.8		22%	88%	38%	77%	20%
Slickwater	127	0.81	-	(0.01)	228	248	(0.01)	1.4		86%	0%	2%	19%	55%
Nitrified Slickwater	35	0.81	-	0.42	25	40	0.01	(1.9)		4%	78%	85%	65%	76%
X-linked foam, CO2	25	0.80	-	(0.13)	146	(952)	(0.08)	34.6		63%	29%	28%	35%	2%
Poly CO2 (Nitrated)	11	0.68	-	0.53	(682)	(4,426)	(0.22)	100.0		63%	22%	68%	79%	36%
Multiple Fluid Types	12	0.77	-	1.10	(358)	(1,973)	7.65	0.1		1%	8%	2%	38%	22%

The model that results for the slickwater wells is shown by Equation 6 and according to Table 24:

$B12 = 0 + 228 \times FS + 248 \times PC - 0.01 \times LL - 0.01 \times Fluid + 1.4 \times Sand$…….Equation 6

A positive coefficient means that production rate will increase if that variable increases. So in Equation 6, if one fracture stage is added, the B12 will increase by 228 Mcf/day. If one PC is added, the B12 will increase by 248 Mcf/day. A negative coefficient means the production rate will decrease if that variable increases. Both fluid volume and lateral length have negative coefficients, which is counter-intuitive. Also, notice that the intercept is being forced to be zero. The P-value indicates the probability of each coefficient being zero. So the higher the P-value, the less influence the variable has on the model.

Table 24- Model 1 regression summary – grouped by fracture fluid type

			Model Coefficient (Mcf/d per unit of variable)									
		Adj.	LL	FS	PC	Fluid	Sand	*Probaility that Coefficient = 0*				
Frac Fluid Type	Count	R^2	(ft)			(bbl)	(tons)	LL	FS	PC	Fluid	Sand
Regression Model 1a												
Linear Foam, N2	41	0.84	(0.18)	144	(519)	0.05	22.2	49%	23%	60%	59%	10%
POLY Co2	98	0.79	0.06	**180**	375	(0.00)	6.2	72%	**5%**	19%	99%	24%
Linear Foam, CO2	50	0.67	0.28	21	(974)	0.02	14.8	22%	88%	38%	77%	20%
Slickwater	127	0.81	(0.01)	**228**	**248**	(0.01)	1.4	86%	**0%**	**2%**	19%	55%
Nitrified Slickwater	35	0.81	**0.42**	25	40	0.01	(1.9)	**4%**	78%	85%	65%	76%
X-linked foam, CO2	25	0.80	(0.13)	146	(952)	(0.08)	**34.6**	63%	29%	28%	35%	**2%**
Poly CO2 (Nitrated)	11	0.68	0.53	(682)	(4,426)	(0.22)	100.0	63%	22%	68%	79%	36%
Multiple Fluid Types	12	0.77	**1.10**	(358)	**(1,973)**	7.65	0.1	**1%**	8%	**2%**	38%	22%
Regression Model 1b												
Linear Foam, N2	41	0.83	0.04	115	837	0.05		85%	34%	17%	61%	
POLY Co2	98	0.79	0.13	**193**	**520**	0.01		39%	**3%**	**3%**	87%	
Linear Foam, CO2	50	0.67	0.37	21	(131)	0.03		9%	88%	88%	61%	
Slickwater	127	0.80	(0.01)	**234**	**280**	(0.03)		92%	**0%**	**0%**	25%	
Nitrified Slickwater	35	0.81	**0.38**	31	18	0.00		**2%**	73%	92%	72%	
X-linked foam, CO2	25	0.78	(0.03)	240	777	0.01		94%	36%	26%	95%	
Poly CO2 (Nitrated)	11	0.70	(0.18)	(541)	4,216	0.49		82%	29%	47%	18%	
Multiple Type	12	0.79	**0.98**	(259)	**(1,701)**	0.12		**1%**	10%	**2%**	6%	

Table 25 shows the second model for each area. The coefficients with P-values less than 5% are shaded yellow.

Table 25- Model 2 regression summary – grouped by fracture fluid type

			Model Coefficient (Mcf/d per unit of variable)					Probability that Coefficient = 0				
Frac Fluid Type	Count	Adj. R^2	LL/PI (ft)	FS	PC	Fluid/PI (bbl)	Sand/PI (tons)	LL/PI	FS	PC	Fluid/PI	Sand/PI
Regression Model 2a												
Linear Foam, N2	41	0.83	(0.75)	106	273	0.17	16.1	65%	25%	70%	78%	27%
POLY Co2	98	0.80	1.18	**163**	**535**	0.31	(2.3)	10%	**1%**	**0%**	38%	74%
Linear Foam, CO2	50	0.67	1.17	142	(587)	0.10	8.1	39%	23%	55%	85%	53%
Slickwater	127	0.81	(0.35)	**108**	**381**	0.10	1.6	45%	**2%**	**0%**	19%	71%
Nitrified Slickwater	35	0.79	0.09	71	**428**	(0.29)	15.7	94%	44%	**0%**	20%	22%
X-linked foam, CO2	25	0.79	(1.31)	(21)	734	(0.54)	32.4	42%	79%	8%	31%	7%
Poly CO2 (Nitrated)	11	0.68	3.04	(725)	(3,153)	(2.42)	101.9	72%	36%	78%	70%	32%
Multiple Type	12	0.72	1.06	91	**826**	(0.91)	10.4	66%	65%	**4%**	39%	63%
Regression Model 2b												
Linear Foam, N2	41	0.83	(0.07)	200	579	0.55		78%	10%	37%	30%	
POLY Co2	98	0.80	0.10	154	**496**	0.48		47%	6%	**3%**	14%	
Linear Foam, CO2	50	0.67	0.35	46	(232)	0.32		12%	69%	80%	51%	
Slickwater	127	0.81	(0.04)	**130**	**387**	**0.11**		64%	**1%**	**0%**	**3%**	
Nitrified Slickwater	35	0.81	**0.36**	47	60	0.01		**2%**	53%	69%	92%	
X-linked foam, CO2	25	0.78	(0.03)	234	749	0.14		91%	25%	16%	75%	
Poly CO2 (Nitrated)	11	0.81	**0.36**	47	60	0.01		**2%**	53%	69%	92%	
Multiple Type	12	0.79	**0.93**	(273)	**(1,142)**	**0.97**		**1%**	8%	**3%**	**4%**	

We performed multivariate regression analysis on all four models on each area and generated Table 26 and Table 27.

Table 26- Model 1 regression summary – grouped by area

Area	Count	Adj. R^2	Model Coefficient (Mcf/d per unit of variable)					Probaility that Coefficient = 0				
			LL (ft)	FS	PC	Fluid (bbl)	Sand (tons)	LL	FS	PC	Fluid	Sand
Regression Model 1a												
Altares	23	0.86	0.25	150	153	(0.01)	(1.0)	22%	21%	62%	21%	87%
Dawson	29	0.82	0.28	15	2,829	0.09	(16.3)	51%	94%	30%	49%	49%
Groundbirch	15	0.90	0.05	90	579	(0.04)	(1.2)	87%	60%	11%	32%	81%
Parkland	15	0.95	0.54	21	(5,511)	0.07	45.2	23%	94%	21%	76%	14%
Septimus	15	0.82	0.15	(55)	(486)	0.04	9.8	73%	85%	92%	25%	82%
Sunset	28	0.91	0.12	**149**	**361**	0.01	(1.4)	25%	**2%**	**2%**	58%	62%
Sunrise	29	0.86	0.15	76	(804)	0.06	9.0	47%	38%	7%	6%	29%
Swan	166	0.80	0.08	**105**	276	0.00	**8.4**	42%	**3%**	12%	58%	**2%**
Town	43	0.86	0.42	133	**473**	(0.02)	(0.7)	25%	41%	**1%**	6%	87%
Regression Model 1b												
Altares	23	0.79	0.25	152	120	(0.01)		21%	19%	60%	6%	
Dawson	29	0.83	0.22	58	1,238	0.08		60%	76%	39%	54%	
Groundbirch	15	0.78	0.01	109	572	(0.04)		98%	45%	10%	26%	
Parkland	15	0.83	0.18	71	844	0.08		65%	82%	47%	75%	
Septimus	15	0.68	0.12	(58)	631	0.04		76%	83%	65%	6%	
Sunset	28	0.92	0.10	**148**	**327**	0.01		29%	**2%**	**1%**	60%	
Sunrise	29	0.86	0.26	86	(456)	0.05		17%	32%	10%	9%	
Swan	166	0.80	0.17	**118**	**493**	0.01		8%	**2%**	**0%**	28%	
Town	43	0.86	0.39	135	**475**	**(0.02)**		23%	39%	**1%**	**4%**	

Table 27- Model 2 regression summary – grouped by area

Area	Count	Adj. R^2	Model Coefficient (Mcf/d per unit of variable)					Probaility that Coefficient = 0				
			LL/PI (ft)	FS	PC	Fluid/PI (bbl)	Sand/PI (tons)	LL/PI	FS	PC	Fluid/PI	Sand/PI
Regression Model 2a												
Altares	23	0.76	2.86	183	241	(0.03)	(12.1)	24%	8%	31%	91%	54%
Dawson	29	0.82	2.83	250	1,742	0.04	(20.1)	42%	13%	41%	96%	44%
Groundbirch	15	0.79	(1.05)	69	**566**	(0.69)	14.0	67%	55%	**1%**	9%	37%
Parkland	15	0.83	2.87	352	(6,955)	0.79	39.4	33%	6%	23%	59%	20%
Septimus	15	0.64	0.89	201	(1,761)	0.24	7.3	71%	35%	74%	26%	87%
Sunset	28	0.91	0.91	**188**	**405**	0.14	(4.0)	49%	**1%**	**0%**	53%	66%
Sunrise	29	0.88	(2.07)	14	**(474)**	**1.75**	19.6	24%	85%	**2%**	**0%**	15%
Swan	166	0.81	0.90	**108**	**559**	0.09	3.1	8%	**0%**	**0%**	28%	53%
Town	43	0.85	(0.52)	37	**685**	(0.14)	12.1	86%	76%	**1%**	49%	30%
Regression Model 2b												
Altares	23	0.76	0.22	90	193	(0.15)		33%	44%	44%	36%	
Dawson	29	0.82	0.25	89	1,563	0.01		56%	65%	38%	99%	
Groundbirch	15	0.81	0.22	(4)	**394**	**(0.63)**		33%	98%	**4%**	**3%**	
Parkland	15	0.83	0.19	147	(116)	0.93		62%	38%	95%	54%	
Septimus	15	0.68	0.18	112	(619)	0.26		66%	64%	65%	6%	
Sunset	28	0.92	0.08	**156**	**369**	0.09		53%	**2%**	**0%**	73%	
Sunrise	29	0.88	(0.04)	133	**(395)**	**1.55**		83%	9%	**4%**	**0%**	
Swan	166	0.80	0.16	**116**	**505**	0.13		10%	**2%**	**0%**	9%	
Town	43	0.85	0.01	122	475	0.07		97%	47%	10%	60%	

We did not sub-group by both area and fracture fluid type mainly because the resulting number of wells was too small. We do not have enough wells in each area. So if we want to perform regression analysis by area, we need to add more data to our database and analyze it again.

Notice that the slickwater wells are widely scattered along the play since the reservoir properties probably vary significantly across the play, then you might assume no adequate model based solely on completion data could be found. However, by applying multivariate regression analysis method, PC and FS show a stronger correlation to B12 than the other variables especially for slickwater wells. On the other hand, completed lateral length does not show a strong correlation to production. Sand and fluid are correlated in only a few specific cases.

4.5 Monte Carlo Modeling for Slickwater Wells

The purpose of this section is to generate scatter in the predicted B12 similar to the real data. This is accomplished by increasing the variance of the inputs' distributions. We used the slickwater fracture fluid type dataset with Multivariate regression analysis to determine the best formula to predict the well performance. We used the Monte Carlo regression to impose the uncertainty on each model and decided which model best reproduced the real production data. The models we evaluated are as follows:

1. LL, FS, PC per Stage, Fluid, Intercept: 0
2. LL , FS, PC per Stage, Fluid , Intercept
3. LL per Stage, FS, PC per Stage, Fluid per Stage, Intercept: 0
4. LL per Stage, FS, PC per Stage, Fluid per Stage , Intercept

We ran the multivariate regression for each model and then generated output summary tables such as Table 28. In the output summary, the mean and standard deviation of each coefficient variable are used to determine the best distribution for each completion parameter coefficient. Moreover, we generated best-fitted distributions for each variable based on real data to create the desired scattered. We explain the process for the third model (our best model) in the next section and the rest of the models are in Appendix A.

4.5.1 Monte Carlo Application

In this model, the intercept is zero (no completion, no production) and all parameters are on a per stage basis. The coefficients of all parameters (Lateral length per stage, FS, PC/stage and Fluid/stage) are positive which shows increasing in each of them will increase the B12.

B12 =0.03×LL/Stage + 169×FS + 284×PC /Stage + 0.11×Fluid/Stage ………Equation 7

The output summary of the model is:

Table 28-Output summary- LL per Stage, FS, PC per Stage, Fluid per Stage, intercept=0

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.91
R Square	0.82
Adjusted R Square	0.81
Standard Error	1,110.51
Observations	127.00

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4.00	688,819,298.07	172,204,824.52	139.64	0.00
Residual	123.00	151,687,135.68	1,233,228.75		
Total	127.00	840,506,433.76			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*ower 95.0%*	*pper 95.0%*
Intercept	-	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
LL/Stage	0.03	0.29	0.09	0.93	(0.54)	0.59	(0.54)	0.59
FS	169.15	42.32	4.00	0.00	85.38	252.92	85.38	252.92
PC	284.18	95.62	2.97	0.00	94.91	473.45	94.91	473.45
Fluid/Stage	0.11	0.24	0.45	0.65	(0.37)	0.59	(0.37)	0.59

In Table 28, each coefficient is used as the mean for the distribution for example; FS has a normal distribution with the mean equal to 169.1 and a standard deviation of 80.4, which is two times the original standard deviation in the output summary (Fig. 35). Notice that we truncated the distribution between four times the standard deviation around the mean the in order to eliminate the negative part of the distribution, minimize negative B12 as much as possible and generate the desired scattered in the coefficient. We used same distribution for the other three variables but different variance multipliers and truncation ranges. For the variables with less impact on B12 such as LL/Stage and Fluid/Stage we use higher variance multiplier (3.5, 3), but for FS and PC per stage with greater impact we use lower multiplier (1.9, 1.7).

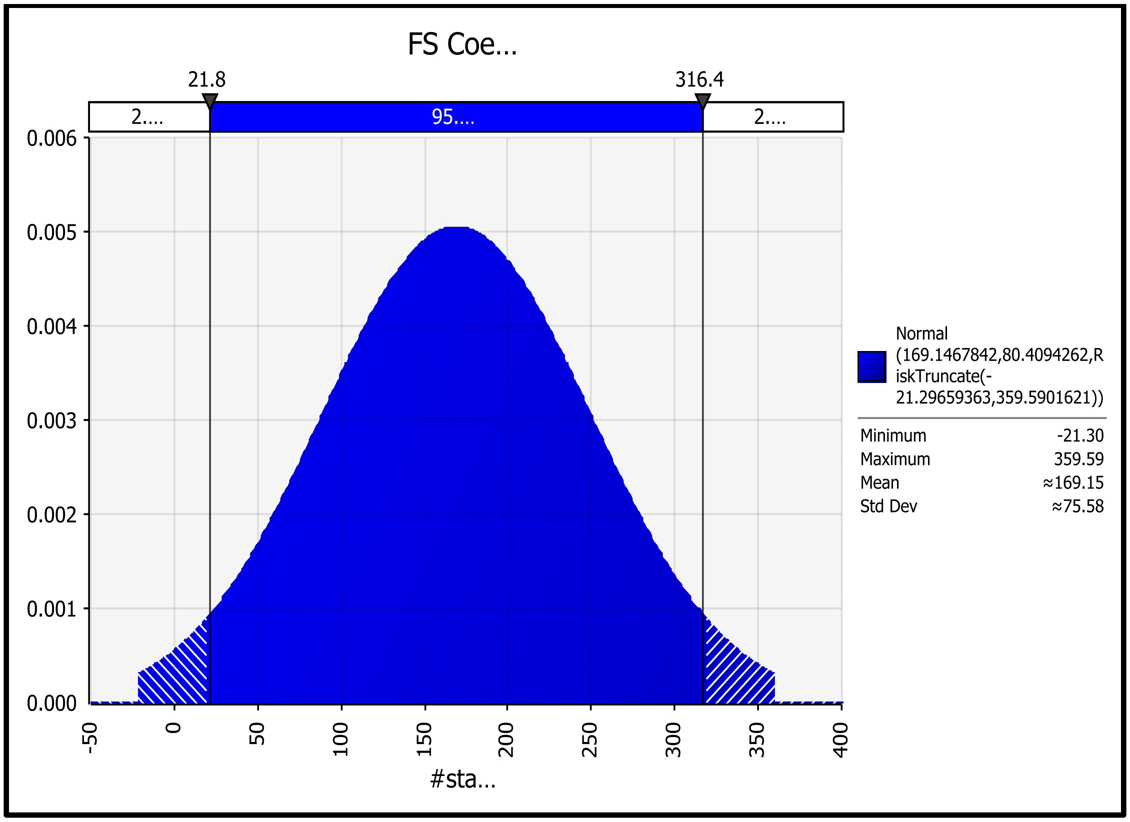


Fig. 35- Risknormal distribution - FS coefficient

In the second step, we build a correlation matrix based on square root of R squared from the 2-D regression for each variable for the 127 slickwater well dataset. Fig. 36 shows an example of the correlation between PC/stage and LL/stage.

The R squared of exponential trend is 0.39. The square root is 0.18, which is shown in Fig. 36 In this manner, 6 completion parameters' plots are drawn and the squared roots of their R squared are used in the correlation matrix. (Appendix A)

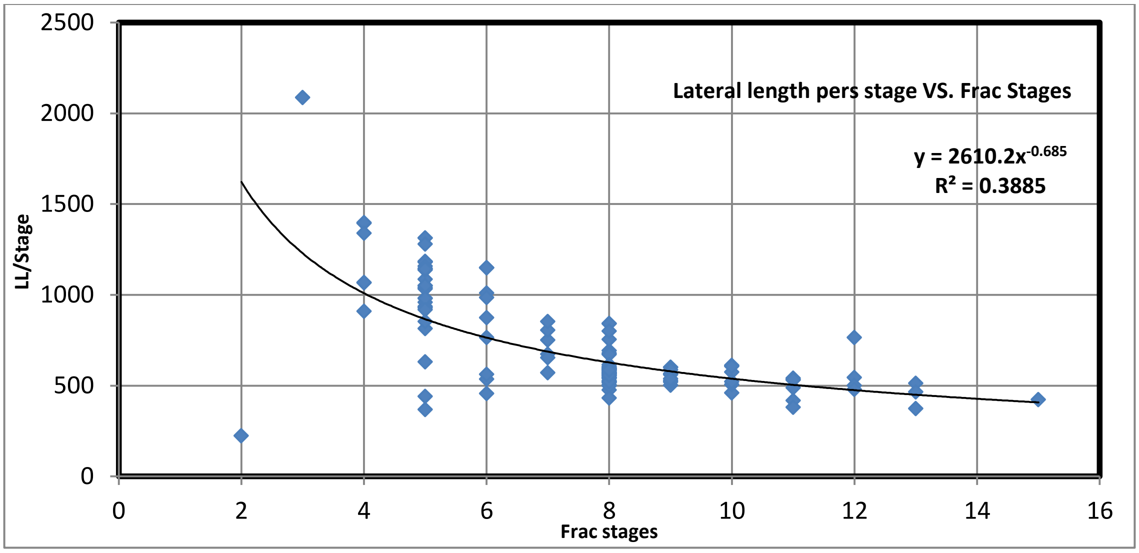


Fig. 36- PC per stage vs. Lateral length

Using the R squared, the correlation matrix is as shown in Table 29:

Table 29- Correlation matrix

@RISK Correlations	LL per stage	FS	PC	Fluid per stage
LL per Stage	1			
FS	0.62	1		
PC	0.18	0.02	1	
Fluid per stage	0.42	0.505	0.081	1

$$B12 = 0.03 \times LL/Stage + 169 \times FS + 284 \times PC\ /Stage + 0.02 \times Fluid/Stage$$

$$\Downarrow$$

Table 30- Summary of coefficient and variables distribution

Coefficent	Distribution	Mean	(Standard error) Standard deviation	Standard deviation Multiplier
LL per stage	Normal	0.03	0.29	3.5
FS	Normal	169.15	42.32	1.9
PC	Normal	284.18	95.62	1.7
Fluid per stage	Normal	0.11	0.24	3

We truncated coefficients between +4δ & - 4δ in order to reduce the number of negative B12's. We tried many truncation ranges and decides +4δ & - 4δ is the best because it results in minimum B12 while keeps the average B12 close to the real B12. Each variables distribution was determined by the best-fit distribution from the completion data in our database (Table 30 and Table 31). To force the simulator to model the actual range of values we truncated their distribution between the minimum and maximum of each completion parameter.

$$B12 = 0.03 \times LL/Stage + 169 \times FS + 284 \times PC\ /Stage + 0.02 \times Fluid/Stage$$

$$\Downarrow$$

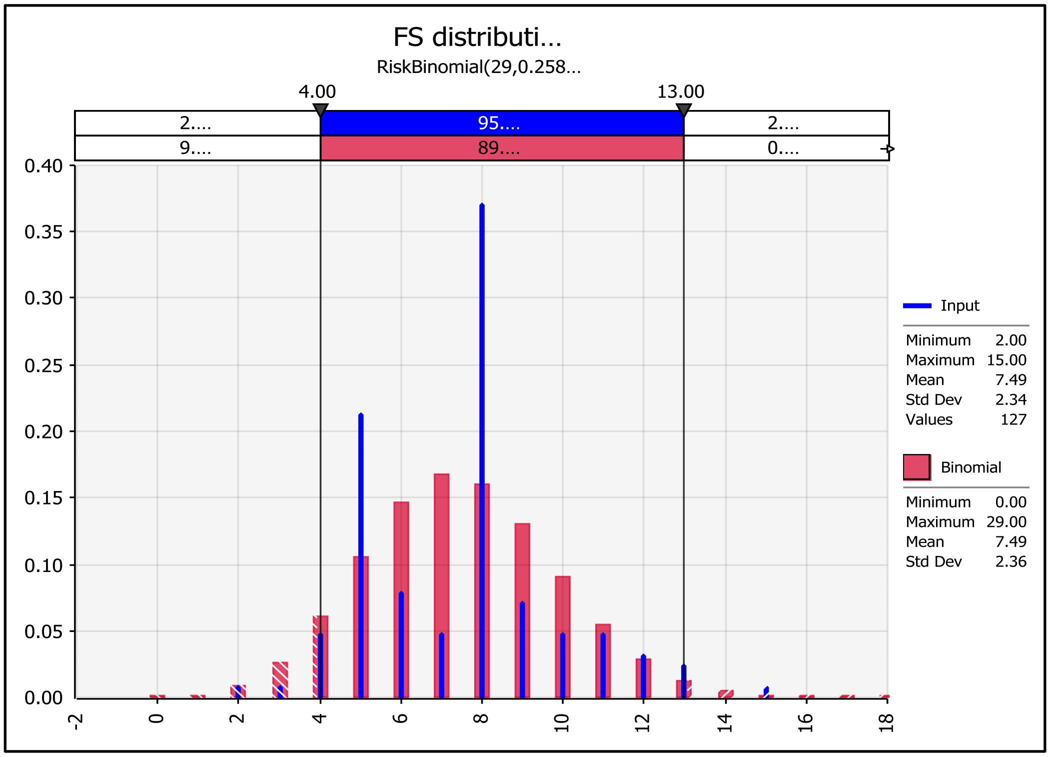
Table 31- Variables distribution

Variables	Distribution
LL per stage	Loglogistic
FS	Binomail
PC	Normal
Fluid per stage	Loglogistic

4.5.2 Monte Carlo Regression Results

As shown in Table 30 & Table 31, all of the coefficients have a normal distribution and truncate between μ±4*δ. The variable distributions are based on the best-fit distribution (Maximum chi-sq.). Table 32 shows FS as a binomial distribution. The blue bars are the real data; the red bars are the fitted distribution. As shown the slickwater wells have an average FS equal to 7.49 and a standard deviation of 2.34. The red dots are the best distribution fit of the real data. For the number of fracture stages in slickwater wells, the distribution is binomial with an average of 7.49 and a standard deviation of 2.36, which is close to the real data average and standard deviation. Moreover, all variables are truncated between the minimum and the maximum of the real data to prevent generation of data out of range. For example, the FS distribution is truncated between 2 and 15 (the actual minimum and maximum number of fracture stages). A most useful Monte Carlo output is the probability plot (Fig. 37) that illustrates the real data distribution (blue dots), the deterministic outcome (red dots) and the probabilistic outcome (green dots).

Table 32-FS distribution-Riskbinomial



The correlation matrix helps the Monte Carlo random number generator to choose random variables which are correlated to each other. For example, it is obvious that with increasing lateral length, FS will increase. Therefore, the software will not choose a long lateral length with very few FS. With these correlations imposed, the model will predict datasets similar to those seen in the real world.

Nineteen thousand and two hundred twenty realizations were produced in an auto iteration mode, stopping when the mean of the B12 converged within a 1% tolerance.

Fig. 37 illustrates our ability to calculate the B12 from Monte Carlo simulation, which matches 95% of the real data range. One point eight percent of these B12 is negative. This model generates the fewest negative B12's compared to the other three models mentioned at the beginning of the section.

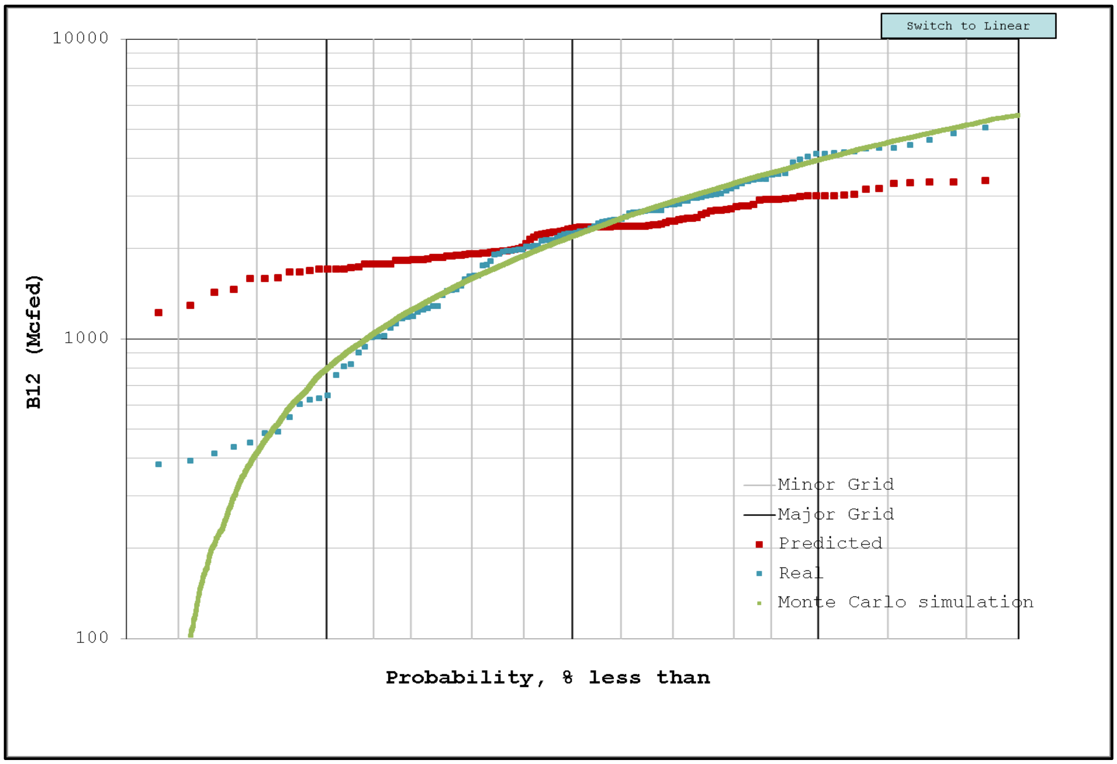


Fig. 37- Probability plot –real &Monte Carlo simulation

In Fig. 37 the red dots are the output of the multivariate regression (deterministic) and the green dots are the output of the Monte Carlo simulation (probabilistic). As you can see, the green dots follow the blue dots over 95% of the data range, indicating an acceptable model. Fig. 38, a B12 vs. # FS plot, show a best fit line passes for both R-squares of Monte Carlo simulation data (blue diamond) and real data (red diamond) with 0.18 and 0.085, respectively. As shown by Fig. 38, a few negative B12's occur with the Monte Carlo simulation.

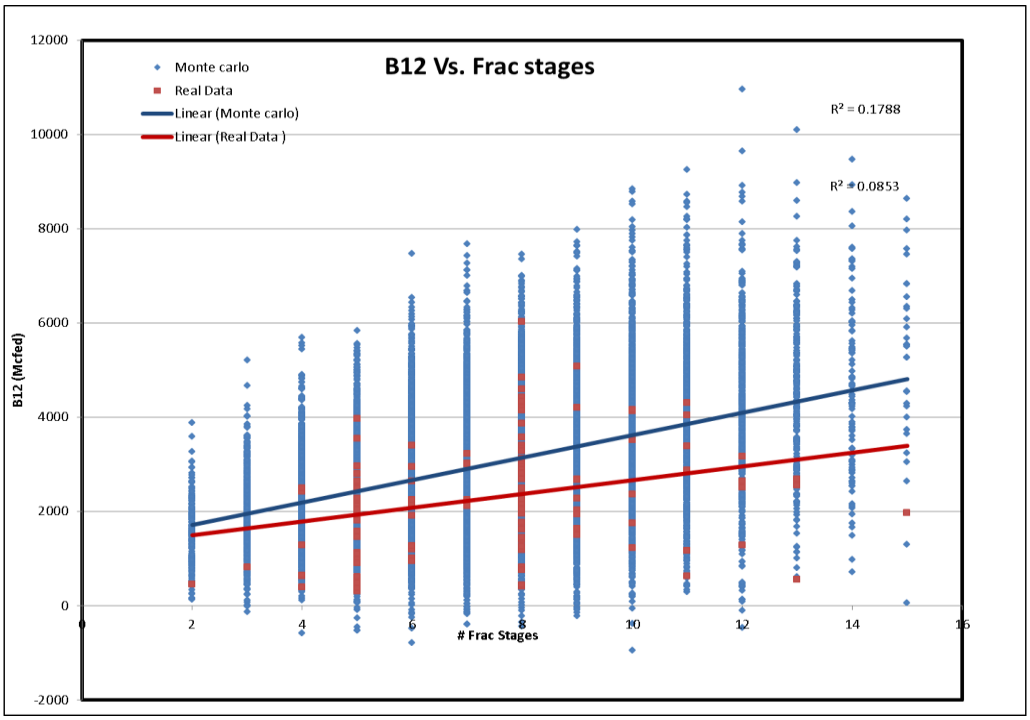


Fig. 38- B12 vs. # FS

Fig. 40 shows a summary of a Monte Carlo simulation run. Fig. 39 is a tornado plot, which shows the importance of each coefficient and variable on the model. As shown in Fig. 40, the FS has the most impact on the model followed by PC.

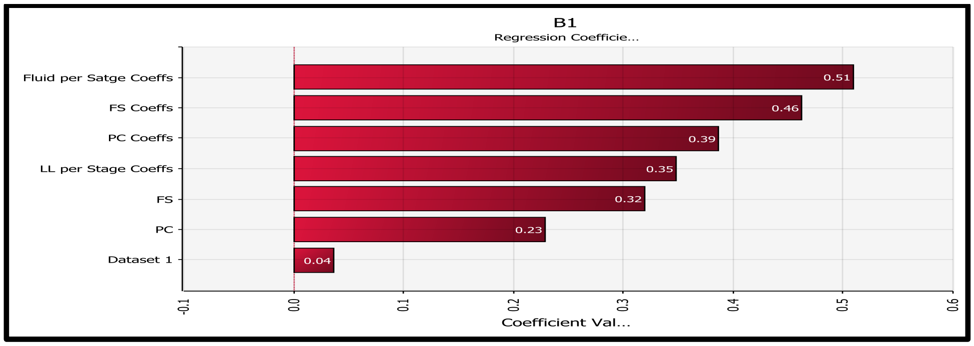
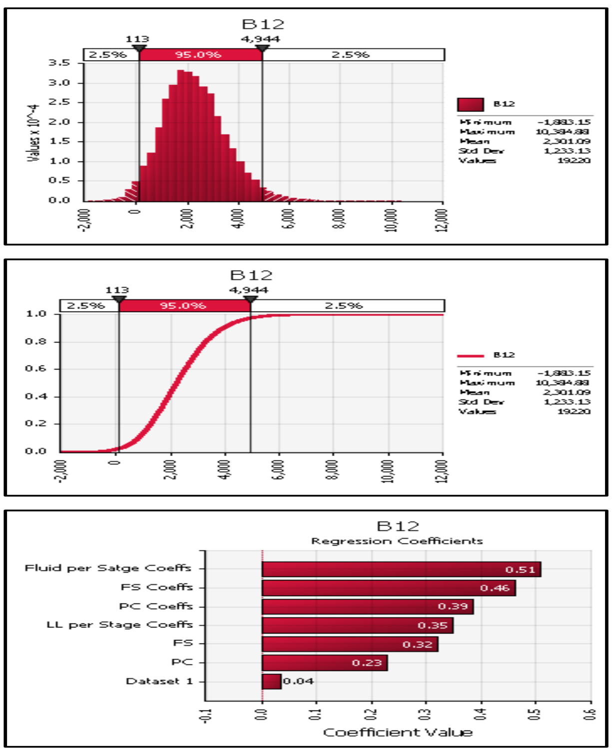


Fig. 39- Tornado chart-model three



Simulation Summary Information	
Workbook Name	Copy of Slickwater-3-Modi
Number of Simulations	1
Number of Iterations	19220
Number of Inputs	8
Number of Outputs	1
Sampling Type	Latin Hypercube
Simulation Start Time	8/14/13 20:32:18
Simulation Duration	00:01:59
Random # Generator	Mersenne Twister
Random Seed	605097913

Summary Statistics for B12			
Statistics		**Percentile**	
Minimum	-1883.145709	**5%**	417.9602908
Maximum	10384.88451	**10%**	802.9603278
Mean	2301.093953	**15%**	1065.36868
Std Dev	1233.125764	**20%**	1260.959645
Variance	1520599.15	**25%**	1435.909655
Skewness	0.424231559	**30%**	1603.230459
Kurtosis	3.417041701	**35%**	1760.570581
Median	2212.293602	**40%**	1908.534471
Mode	1774.141557	**45%**	2057.599394
Left X	113.4949575	**50%**	2212.293602
Left P	3%	**55%**	2369.571911
Right X	4943.983563	**60%**	2533.094446
Right P	98%	**65%**	2701.008795
Diff X	4830.488605	**70%**	2882.077666
Diff P	95%	**75%**	3062.923937
#Errors	0	**80%**	3285.198261
Filter Min	Off	**85%**	3570.543339
Filter Max	Off	**90%**	3917.116658
#Filtered	0	**95%**	4461.56605

Regression and Rank Information for B12			
Rank	**Name**	**Regr**	**Corr**
1	Fluid per Satge Co	0.509	0.512
2	FS Coeffs	0.463	0.450
3	PC Coeffs	0.386	0.376
4	LL per Stage Coef	0.348	0.341
5	FS	0.319	0.339
6	PC	0.229	0.236
7	Dataset 1	0.036	0.210
8	LL per Stage	0.000	0.210441653

Fig. 40- Output report of B12

We repeated the analysis for other three models; with results illustrated in Table 33. We consider the best model to be the third model for several resources:

1. High F : 139.64,

2. Low Significance F : 1.48466E-44,
3. High adjusted R squared : 0.81,
4. Very high P-Value for LL/Stage and Fluid/Stage : 0.93 , 0.65 and
5. Low percentage of B12: 1.9%.

Table 33-Summary of four models-Monte Carlo simulation

Model (127 Data Points)	F	Significance F	Adjusted R2	Number of Iteration	% Negative B12	Least important coeffceint	P-value of Least important coeffceint
LL , FS, PC per Stage, Fluid , Intercept :0	141.36	8.04814E-45	0.81	13000	3.20%	Lateral Length	0.95
LL , FS, PC per Stage, Fluid , Intercept	4.85	0.001149629	0.11	19220	3.50%	Lateral Length	0.54
LL per Stage, FS, PC per Stage, Fluid per Stage , Intercept :0	139.64	1.48466E-44	0.81	19220	1.9%	Lateral Length per Stage	0.93
LL per Stage, FS, PC per Stage, Fluid per Stage , Intercept	4.98	0.000945625	0.11	19200	3.40%	Frac Fluid per Stage	0.97

Therefore, the best equation to predict B12 derive for slickwater wells is shown as Equation 7:

$$\boxed{B12 = 0.03\times LL/Stage + 169\times FS + 284\times PC/Stage + 0.11\times Fluid/Stage}$$

This formula indicates incremental increases in each variable will affect the B12. For example, adding one FS in a completion plan would add 169 Mcf/day to the B12 and adding one PC in the completion would add 284 Mcf/day to the B12. Notice that PC and FS are the most important completion parameters.

4.6 Type Curves

In this section, we built the type curves by area to use them as the inputs for the economic analysis. Fig. 41 is an example of a two-well zero time graph with the average being a type curve. We use both the historical and forecasted data to compute the average. For this example, we show two wells that have materially different start dates and have much different production volumes. The red decline curve is a poor quality well (B1≈1 MMcf) the black represents a good quality well (B1≈8 MMcf) and the green curve is the average of these two wells. The triangle symbols show historical data and the solid line is forecasted data. As you can see, the green curve is the average of blue and red curves. The smooth part of the green curve is the result of averaging two forecasted points from each well A&B. However, the less smooth portion indicates an average that includes historical data. Because the historical data of the two wells lasts no more than three years, the green curve becomes smooth after three years.

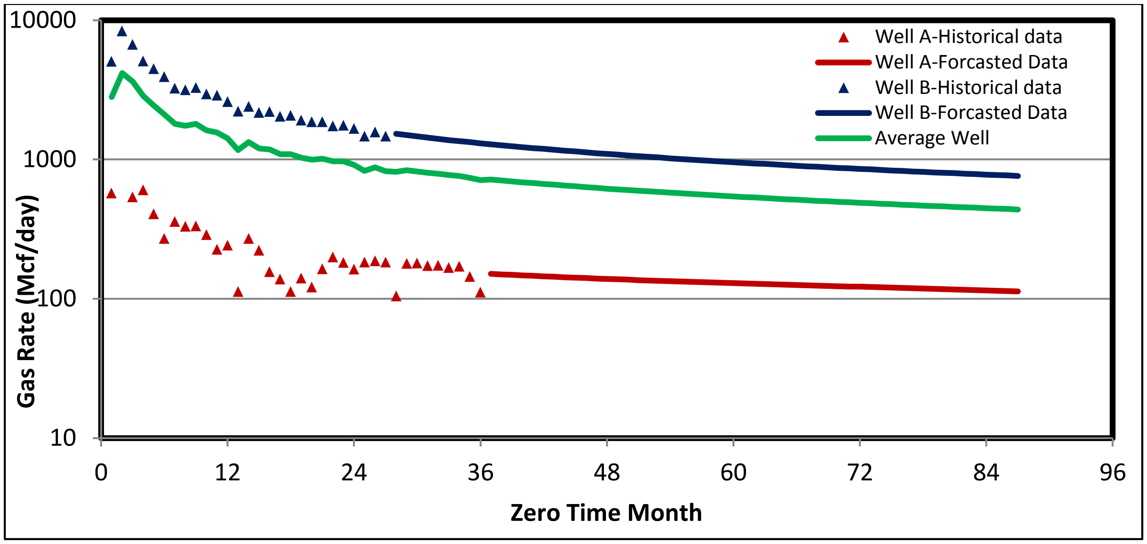


Fig. 41- Type curve example

4.6.1 Methodology

In this section, our main goal is to predict the well performance by area. Therefore we generated type curves in each area and then adjusted them by multiplying the initial production by the B12 adjustment ratio (we will explain later) in order to prepare our inputs (Qi, Di, bexp) by area for economic analysis. In our research, our final objective is to make economic maps for the slickwater wells in the Montney formation, showing rate of return and PV10. To do this, we undertook the following steps:

1. Calculate a development-well B12 with 9 fracture stages, 3 perforation clusters per stage, 550 ft/stage and historical average fluid /stage by area. Then use Equation 7 to compute a B12 by area, assuming all wells are completed with the same LL per stage, FS and PC per stage.

$$\boxed{B12 = 0.03 \times LL/Stage + 169 \times FS + 284 \times PC/Stage + 0.11 \times Fluid/Stage}$$

2. Calculate the historical B12 from the best regression model using mean values for FS, PC, LL/stage and Fluid/stage.
3. Compute an adjustment factor as the ratio of development B12 to historic B12

$$\text{B12 adjustment}=\frac{\textbf{Developmental B12}}{\textbf{Historical B12}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots.. \text{ Equation 8}$$

4. Adjust the type curves by area. Do this by multiplying each type curve Qi by the B12 adjustment in order to shift the type curves up or down.

$$\text{Adjusted type curve}=\text{Type curve} \times [(\text{Developmental B12})/ (\text{Historical B12})] \qquad \text{Equation 9}$$

5. Collect drilling and completion costs by area based on public domain data.
6. Run an economic analysis for three different gas prices ($3, $4, $5).
7. Generate rate of return (ROR) and PV10 by area and create maps for ROR and PV10 by area.

4.6.2 Area Type Curves

UGR made type curves by following these steps in each area:

- Forecast individual wells with more than two years of production and use to compute a preliminary type curve;
- Used the preliminary type curve (above step) as a guide to forecast production on wells with less than 2 years of production;
- Compute a final type curve for all wells in area using zero time averaging of both forecasted and historical data from all wells.

Fig. 42 is an example of final type curve in swan area. These data are shown in red dots. As shown in Fig. 42, regression data and gas real data have a very good match because the dots fully covered the regression line. The regression line is the best line of gas data. By averaging the historical and forecasted data, the number of wells will be constant over 180 months.

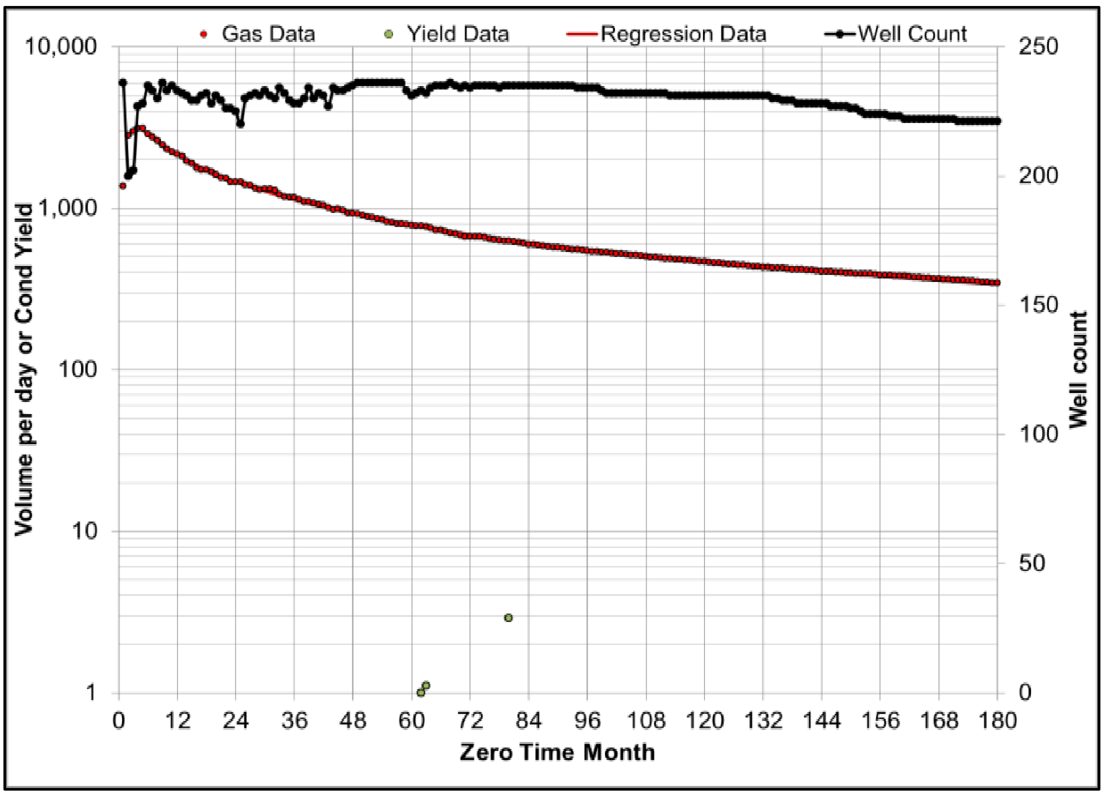


Fig. 42- Type curve example-Swan-HZ-all

4.6.3 Type Curve Adjusted by Area for New Well Performance and Completion Differences

Qi, Di and b exponential of the zero time type curves and adjusted type curves are summarized by area in Table 34. In addition, Table 34 shows the development-well and historic-well B12 and their ratio for each area.

Table 34- Type curve information

											Adjusted type curve	Iniitial type curve information by area		
Area	Count	B12 (Mcfd)	B1 (Mcfd)	Completed Lateral Lengthper stage (ft/stage)	Fracture Stages	Perf Clusters	Fracture Fluid pers stage (bbls/stage)	B12 Development(Mcfd)	B12 Historical(Mcfd)	B12 Adjustment=(Development B12)/(Historical b12)	Qi, vol/d	Qi, vol/d	Di, #/yr	bexp
Altares	18	2,327	4,435	504	10.7	2.9	10,689	2,603	2,979	0.9	2,983	3,414	3.43	2.18
Blair	12	2,433	4,170	578	7.8	3.7	8,550	2,560	2,619	1.0	4,023	4,115	1.77	1.81
Blueberry	1	1,152	3,463	692	4.0	3.0	7,875	2,547	1,778	1.4	2,414	1,685	4.30	1.63
Brassey	6	1,198	2,597	788	5.0	1.8	4,845	2,486	1,527	1.6	2,305	1,416	0.72	1.22
Dawson	31	3,428	4,763	613	7.9	1.0	1,204	2,414	1,668	1.4	5,444	3,762	0.44	0.69
Graham	10	2,274	4,515	619	7.8	2.8	8,501	2,560	2,381	1.1	4,279	3,980	1.08	1.51
Groundbirch_North	2	438	982	988	4.5	3.0	5,807	2,506	1,806	1.4	3,156	2,275	1.21	1.80
Groundbirch_South	20	1,098	2,099	899	6.1	2.8	4,710	2,484	1,963	1.3	2,214	1,750	0.78	1.45
Gundy	6	3,458	5,237	553	9.0	2.7	8,537	2,560	2,546	1.0	4,343	4,318	1.22	1.03
Kobes	4	2,549	3,513	566	8.8	3.0	5,652	2,503	2,512	1.0	3,469	3,482	1.11	1.45
Parkland	16	2,652	4,738	535	7.5	1.0	948	2,408	1,591	1.5	8,104	5,352	1.84	1.43
Septimus	20	1,484	2,957	562	6.4	1.0	3,158	2,453	1,472	1.7	4,397	2,638	0.91	1.47
Sunrise_Sunset	44	2,361	3,827	793	7.0	2.6	3,523	2,460	2,049	1.2	3,566	2,971	0.94	1.50
Swan	156	2,437	3,880	653	7.1	1.3	1,315	2,416	1,611	1.5	5,012	3,342	0.82	1.20
Swan_North	23	2,173	3,234	637	8.3	1.1	1,090	2,411	1,777	1.4	4,105	3,026	0.43	0.88
Town	47	2,372	3,840	553	7.9	2.4	8,362	2,557	2,272	1.1	4,074	3,620	1.73	1.65
Total or Average	**425**													
FS	9													
PC	3													
LL/Stage	550 (ft/stage)													
Best regression Formula														
B12 =0.03×LL/Stage + 169×FS + 284×PC /Stage + 0.02×Fluid/Stage														

As shown by Table 34**,** in some areas the development-well B12 and historic-well B12 are not the same because our regresion model is a general model for all areas in

Montney play not for a specific area. Also, areas with 1 perforation cluster per fracture stages (PC) Shas the largest B1 adjustment factor sinces our imposed PC of 3 is a very large increase in an influential parameters. Because historical B12 is in the denominator of adjustment factor,the result of adjustment factor is higher. Fig. 43 shows a type curve sample with adjustments.

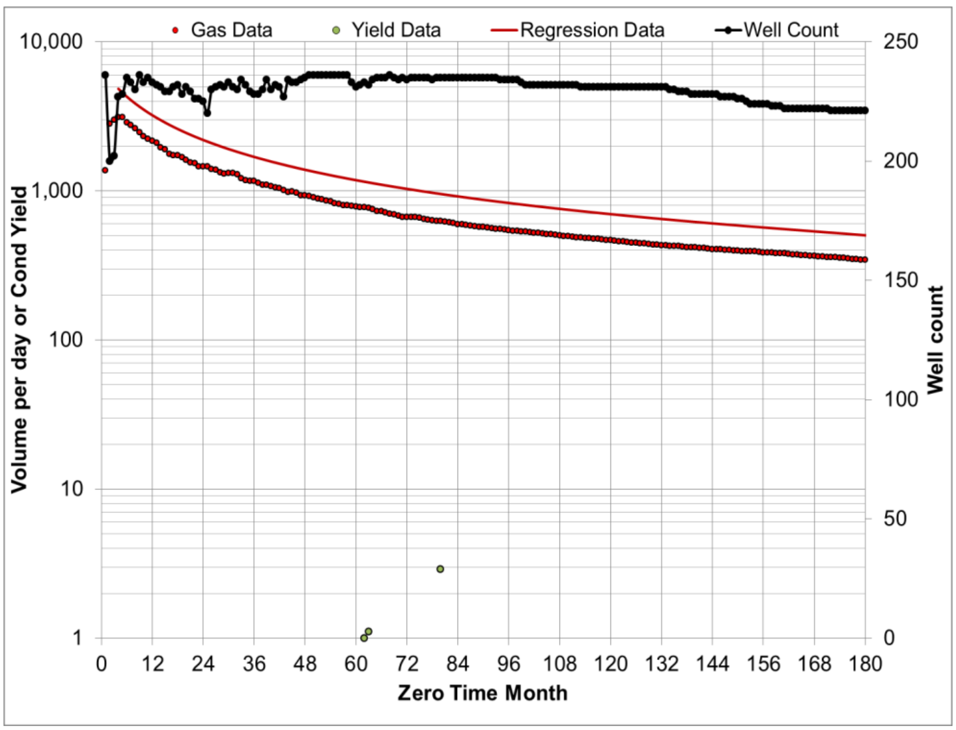


Fig. 43- Adjusted type curve-multiply original Qi by adjustment factor – Swan

4.7 Economics

In this section, we built the drilling and completion cost models. Also, from the previous section we had the production type curves for each area. Using two inputs of production type curve and drilling and completion cost model, we ran economics for each area to compute ROR and PV10.

4.7.1 Cost Model

Table 35 is a summary of drilling and completion costs in each area. Drilling costs are estimated from TVD and drilled days. Duration of drilling is the time between spud and release rig date. Completion costs are estimated from sand total tonnage and load fluid.

Table 35- Summary table of drilling and completion costs in each area

UGRField	Drilled Days	MD (m)	TVD (m)	Estimated Drilling Costs (K$)	Completion Costs (K$)	$/m (MD)	$/m (TVD)	Stages Actual (#)	Completed Length (m)	Avg Proppant Placed per Stage (t)	Total Tonnage	Reported Completion Costs (K$)	Estimated Completion Costs (K$) Estimate	Completion Cost per Stage (K$)	$/T	Load Fluid (m3)	$/m3	Avg Fluid Pumped per Stage (m3)	Avg Frac Spacing (m)	#Wells in each field
ALTARES	52	4349	2488	5658	3968	1317	2276	10	1532	241	2412	6077	5676	619	3292	19433	342	1938	163	79
ATTACHIE	20	3889	1739	1950	3857	503	1121	16	1986	126	1494	3857		299	3101	8709	500	719	148	2
BEG	18	3569	1850	1800	3561	504	1000	8	1515	126	1004		3561	445	3547	6496	548	812	209	1
BLAIR	27	3902	2188	3128	5083	807	1436	8	1389	189	1484	5083		704	3642	9207	574	1199	179	16
BLUEBERRY	27	3546	1925	2867	4779	813	1492	8	1500	174	1284	4779		652	3729	8141	600	1087	218	6
BRASSEY	55	5227	3399	5856	5567	1128	1744	10	1508	134	1411	5981	3830	573	4430	13097	492	1306	185	9
CARIBOU	30	3385	1877	3133	5153	927	1671	8	1279	183	1467	5153		687	3471	8567	595	1071	165	3
DAWSON	15	3926	2055	1303	2294	331	635	10	1665	102	1010	2299	2199	279	2295	1553	1537	155	175	52
FIREWEED	29	3328	1714	3350	5195	1005	1953	8	1464	196	1470	5195		696	3561	8588	606	1147	208	2
GRAHAM	51	4153	2319	5511	5408	1307	2360	9	1579	192	1646	4780	5966	661	3370	11467	540	1341	192	17
GROUNDBIRCH_NORTH	23	4359	2366	2284	3838	525	964	10	1758	122	1118	4073	3731	429	3674	6440	663	673	204	48
GROUNDBIRCH_SOUTH	38	4630	2729	3857	3501	845	1406	8	1694	151	1046	3334	3745	537	3556	5576	1100	904	273	37
GUNDY	34	3727	2033	3500	4617	933	1712	10	1523	165	1524	4966		535	3073	11239	443	1201	166	9
JACKPINE	58	5472	3702	6300	10036	1156	1702	20	1622	160	2567	10036		748	4217	17967	602	1120	96	6
JEDNEY	13	1985	1983		1553			2												1
KOBES	38	4036	2140	4013	7559	988	1808	10	1654	178	1764	7229		781	5289	15636	1084	1538	161	8
LILY	31	3719	2229	3113	7229	834	1428	8	1454	175	1422	4468		599	3148	11504	401	1412	186	8
MONIAS	45	3046	1772	4500	4468	1477	2539	5	902	100	500	3061		612	6122	553	5535	111	180	1
NIG	18	2896	1541	1856	3061	643	1209	8	1108	120	926	4023		539	4354	3657	1750	502	149	9
PARKLAND	17	3534	1953	1765	4023	503	258	12	1336	95	1028	2456	1975	269	2489	3643	1064	319	138	46
SATURN	34	4482	2433	3360	2736	749	308	6	1658	126	731	2670		485	3863	2415	2057	450	306	5
SEPTIMUS	23	3734	1993	2225	3284	601	307	9	1540	142	1067	3454		497	3277	6512	570	841	214	33
SUNDOWN	25	4512	2707	2534	3123	561	936	12	1601	75	766	3123		350	4265	2273	2130	217	158	83
SUNRISE_SUNSET	18	4426	2298	1608	3818	364	700	11	1905	128	1336	3818		390	2587	6662	858	640	183	105
SWAN	22	4524	2741	2355	3406	519	863	12	1570	83	993	3396	3800	320	3612	4816	1305	402	135	40
SWAN_NORTH	19	4579	2400	1862	3427	410	771	11	1950	127	1297	3427		363	2739	4861	1136	475	196	22
TOWER	20	3911	1949	2000	2946	509	1040	10	1667	166	1449	2946		375	2096	8037	369	906	188	4
TOWN	29	3549	1970	2912	4125	821	1481	8	1385	190	1500	4125		601	2856	11002	382	1401	181	41

4.7.1.1 Models by Area

Table 36 shows the historical costs that are based on real drilling and completion cost models for each area. Drilling cost per day is $100, 000 and fixed costs are assumed to be $500,000. For example, in the Altares area the drilling cost (K$) model is:

Drilling Cost = Drilled days*100+500

Based on the formula the average drilling cost is $5,658,000 in the Altares. It took 52 days to drill in Altares. The completion cost thousands of $ is:

Completion Cost = Total tonnage*1.3+94*25.5 or

Completion Cost = ($/T*Tonnage+$/m3*Load fluid)/2000

That results in $3,968,000 in the Altares area.

We used this drilling and completion cost and original production type curve in our economic software as it shown in Table 36.

Table 36- Historical drilling and completion costs by area-used in economic software

UGRField	Estimated Drilling Costs (K$)	Completion Costs (K$)
ALTARES	5658	3968
ATTACHIE	1950	3857
BEG	1800	3561
BLAIR	3128	5083
BLUEBERRY	2867	4779
BRASSEY	5856	5567
CARIBOU	3133	5153
DAWSON	1303	2294
FIREWEED	3350	5195
GRAHAM	5511	5408
GROUNDBIRCH_NORTH	2284	3838
GROUNDBIRCH_SOUTH	3857	3501
GUNDY	3500	4617
JACKPINE	6300	10036
JEDNEY		1553
KOBES	4013	7559
LILY	3113	7229
MONIAS	4500	4468
NIG	1856	3061
PARKLAND	1765	4023
SATURN	3360	2736
SEPTIMUS	2225	3284
SUNDOWN	2534	3123
SUNRISE_SUNSET	1608	3818
SWAN	2355	3406
SWAN_NORTH	1862	3427
TOWER	2000	2946
TOWN	2912	4125

Table 37 shows the developmental drilling and completion costs that we used with the adjusted production type curve for economic analysis. Developmental cost is smaller than historical cost because of doing repetitive tasks and drilling multi-wells in the same pad.

Table 37-Develpmental drilling and completion costs by area-used in economic software

UGR field	Estimated Drilling Costs (K$)	Completion Costs (K$)
ALTARES	4,500.00	4,000.00
BLAIR	3,000.00	3,500.00
BLUEBERRY	2,900.00	3,000.00
BRASSEY	4,500.00	4,000.00
DAWSON	1,300.00	2,300.00
GRAHAM	4,500.00	4,000.00
GROUNDBIRCH_NORTH	2,000.00	3,500.00
GROUNDBIRCH_SOUTH	3,000.00	3,500.00
GUNDY	3,000.00	3,000.00
KOBES	3,500.00	3,500.00
PARKLAND	1,700.00	3,000.00
SEPTIMUS	3,000.00	2,000.00
SWAN	2,300.00	3,200.00
Swan-North	1,900.00	3,000.00
Sunset-Sunrise	1,600.00	3,500.00
TOWN	2,900.00	3,000.00

4.7.2 Economic Inputs and Outputs

Both type curves (Fig. 44) and drilling and completion costs (Fig. 45) (in each area) are inputs of the economic software run to estimate the rate of return and PV10 for each area.

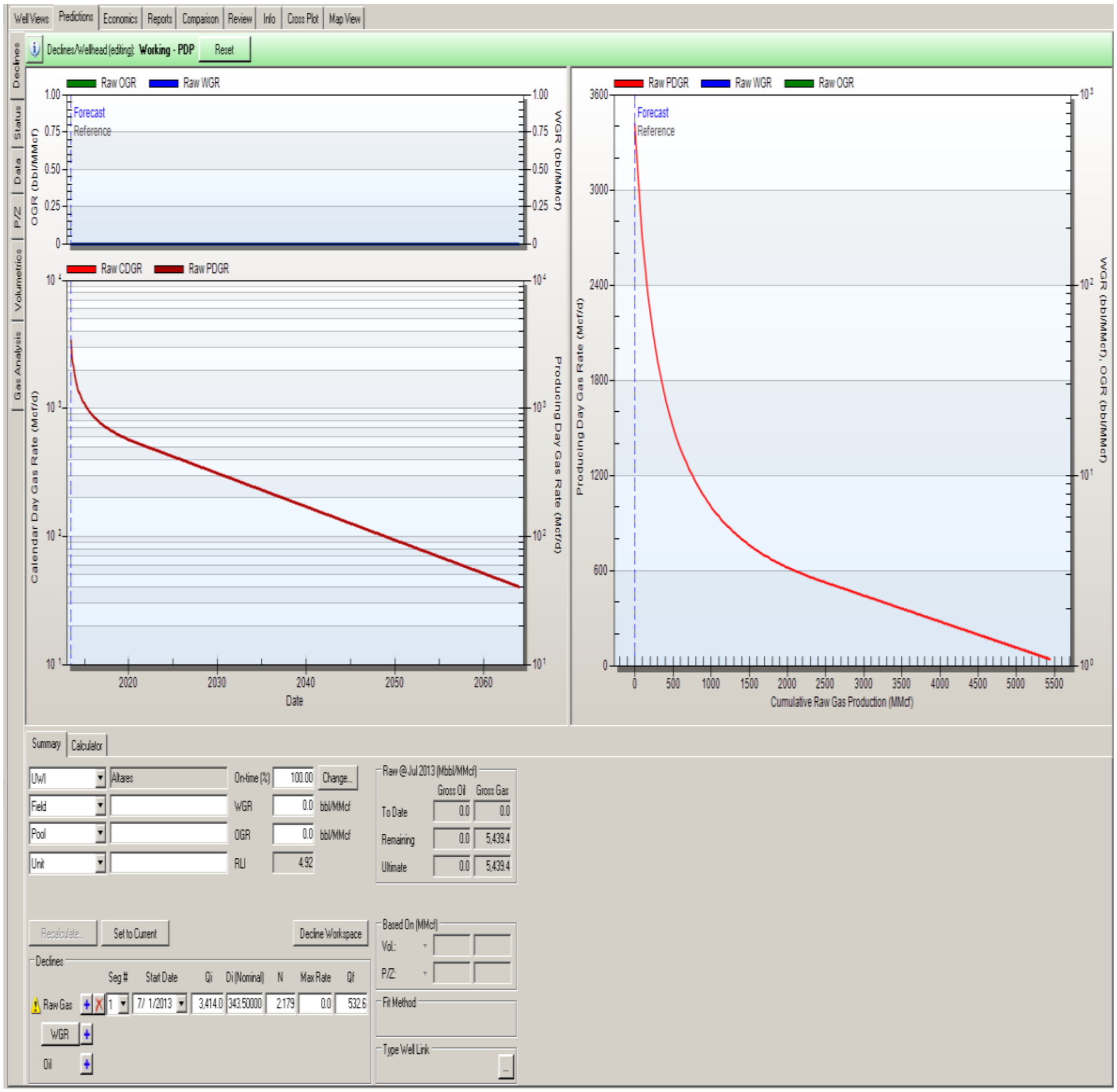


Fig. 44-Type curve as an input of Val-Nav

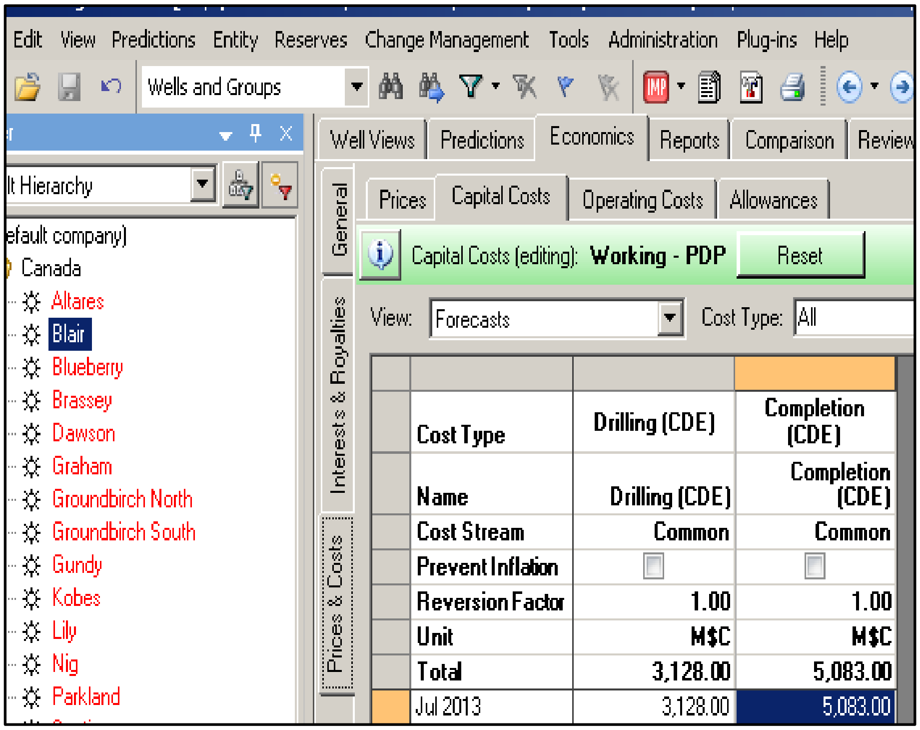


Fig. 45- Drilling and completion cost as an inputs of Val-Nav

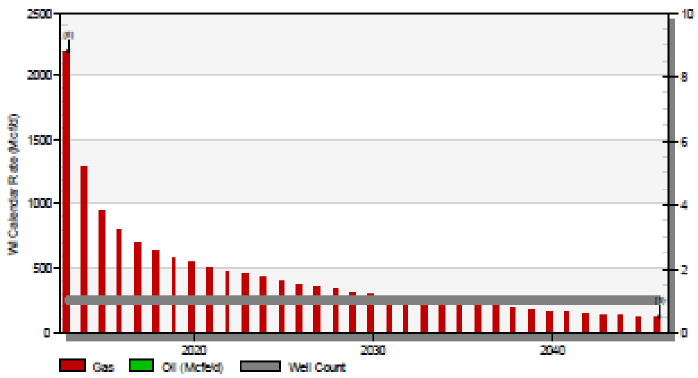
We ran economic analyses six times for each area: three gas price decks for two type curves. The three price decks we used were \$3, \$4, \$5 1MMBTU for gas with no escalation. The two type curves were the initial type curve and adjusted type curve. After completing the economic analysis, we created maps for ROR and PV10. The composition of the produced gas, condensate yield, NGL yields and surface loss are different for each area and these differences had to be accounted for in the analysis. In addition, we applied a royalty credit of \$2,200,000 for the west areas and \$900,000 for the east areas of the Montney play. The West and East area of the Montney play is shown by brown straggled in Fig. 17.

Altares

Price Deck: Fixed 4 Gas
Montney Area Completion Study
Results as of July 01, 2013

Evaluation Parameters

Reserves Category	Proved Developed Producing
Plan	Working
Reference Date	July 01, 2013
Discount Date	July 01, 2013
Econ. Calc. Date	July 01, 2013
Country	Canada
Province	British Columbia
Company Share	100.00 %
Price Deck	Fixed 4 Gas
Price Set	Base Price Set
Economic Limit	Applied - BTCF 0.00 %
Scenario	Fixed 4 Gas
GCA Applied	No
BOE Ratio	6:1 Mcf/bbl
Chance of Success	100.0 %
Chance of Occurrence	100.0 %
Oil Reserves Type	N/A
Gas Reserves Type	Gas



Remaining Reserves / Net Revenue NPV (M$C) / Price

		Gross	WI	RI	Net		0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %	Average
Oil	Mbbl	-	-	-	-	Oil	-	-	-	-	-	-	-
Gas	MMcf	4,920.3	4,920.3	-	3,897.5	Gas	17,206.4	11,133.1	9,220.9	8,307.2	6,747.5	5,770.6	4.21
Liquids	Mbbl	34.3	34.3	-	27.4	Liquids	1,777.5	1,178.9	986.5	893.5	732.8	630.6	64.86
NGL	Mbbl	-	-	-	-	NGL	-	-	-	-	-	-	-
Condensate	Mbbl	-	-	-	-	Condensate	-	-	-	-	-	-	-
C2	Mbbl	-	-	-	-	C2	-	-	-	-	-	-	-
C3	Mbbl	11.9	11.9	-	9.5	C3	238.3	158.1	132.3	119.8	98.3	84.5	25.00
C4	Mbbl	12.4	12.4	-	9.9	C4	744.8	493.9	413.3	374.4	307.0	264.2	75.00
C5+	Mbbl	9.9	9.9	-	7.9	C5+	794.4	526.9	440.9	399.3	327.5	281.8	100.00
Sulphur	MLT	-	-	-	-	Sulphur	-	-	-	-	-	-	-
Total	**MBOE**	**864.3**	**864.3**	**-**	**677.0**	**Total**	**18,983.9**	**12,311.9**	**10,207.4**	**9,200.7**	**7,480.3**	**6,401.1**	**26.86**

Cash Flow NPV (M$C)

	0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %
BT Cash Flow	2,715.4	-846.6	-2,094.0	-2,719.4	-3,836.5	-4,569.2

Risked Capital Costs (M$C)

	Gross	Co. Share
Land (COGPE)	-	-
Exploration (CEE)	-	-
Development (CDE)	9,626.0	9,626.0
Other Capital (CCA)	-	-
Total	**9,626.0**	**9,626.0**

Cash Flow (M$C)

	Co. Share	% of Sales Rev.
Revenue	22,950.2	
Royalties/Burdens	3,966.3	17.3
Operating Cost	6,642.5	28.9
Abandonment/Salvage	-	-
Oth. Rev./Oth. Deduct.	-	-
Capital	9,626.0	41.9
(Credit)/Surcharge	-	-
BT Cash Flow	**2,715.4**	**11.8**

Economic Indicators

	Before Tax
Rate of Return (%)	3.5
Payout (yrs from Jul 2013)	13.9
Payout (date)	May 2027
P/I - 0.0 % Discount	0.28
P/I - 10.0 % Discount	-0.28
Init. Value (M$C/(BOE/d))	5.21

	WI	Co. Share	Net
Op. Cost ($C/BOE)	7.78	7.78	9.81
Cap. Cost ($C/BOE)	11.27	11.27	14.22

Annual Co. Share Cash Flow

Year	Well Count	Rate Mcfe/d	Avg. Price $C/Mcfe	WI Revenue M$C	Royalty Revenue M$C	Roy. / Burden M$C	Operating Cost M$C	Abandon. / Salvage M$C	Other Revenue M$C	Other Deductions M$C	Credit / (Surcharge) M$C	Net Op. Income M$C	Capital Cost M$C	BTax Cash Flow M$C
2013 (6)	1.00	2,295.8	4.48	1,891.3	-	427.8	244.5	-	-	-	-	1,219.3	9,626.0	-8,406.7
2014	1.00	1,350.2	4.48	2,208.5	-	497.6	322.6	-	-	-	-	1,388.3	-	1,388.3
2015	1.00	993.7	4.48	1,624.0	-	365.0	263.6	-	-	-	-	995.3	-	995.3
2016	1.00	830.3	4.48	1,360.6	-	301.9	238.7	-	-	-	-	819.9	-	819.9
2017	1.00	730.3	4.48	1,193.5	-	256.1	224.0	-	-	-	-	713.3	-	713.3
2018	1.00	660.9	4.48	1,080.0	-	222.9	214.9	-	-	-	-	642.2	-	642.2
2019	1.00	608.9	4.48	995.1	-	197.5	208.9	-	-	-	-	588.7	-	588.7
2020	1.00	568.0	4.48	930.8	-	178.0	205.1	-	-	-	-	547.7	-	547.7
2021	1.00	534.1	4.48	872.9	-	161.0	201.8	-	-	-	-	510.0	-	510.0
2022	1.00	503.0	4.48	822.1	-	146.1	199.3	-	-	-	-	476.6	-	476.6
Rem.	1.00	284.2	4.48	9,973.6	-	1,212.4	4,319.1	-	-	-	-	4,442.1	-	4,442.1
32.58 yr		**430.6**	**4.48**	**22,950.2**	**-**	**3,966.3**	**6,642.5**	**-**	**-**	**-**	**-**	**12,341.4**	**9,626.0**	**2,715.4**

Fig. 46- Example of report economic summary-before tax-Altares –fixed $4 gas

4.8 Economic Evaluation

We created maps of rate of return and PV10 assuming all the wells in the play have completed with 3 FS, 9 PC and 550 ft/stage. There are two economic summary reports for each of the three gas prices ($3, $4, $5) in each area:

- Economic detail
- Economic summary

Fig. 46 is an example of the economic summary report. A summary of the $4 gas price analysis for each area before type curve adjustment is shown in Table 38. Table 39 summarizes the after type curve adjustment results. Also, an example of Economic detail report is in appendix A.

Table 38-Economic information (ROR, PV10) –original type curves –by area

	Estimated Drilling Costs (K$)	Completion Costs (K$)	Gas(MMcf)	Liquid (Mbbl)	Condensate (Mbbl)	Liqiuid yield (bbl/MMcf)	Condensate yield (bbl/MMcf)	Capital cost (M$C)	Op. Cost ($/BOE)	Cap. Cost ($/BOE)	PV10 ($)	ROR(%)
ALTARES	5,658.23	3,968.00	4,920.30	34.30	-	6.97	-	9,626.00	7.78	11.27	(1,019.80)	7.20
BLAIR	3,128.19	5,083.25	6,726.40	32.50	-	4.83	-	8,211.00	7.06	7.12	2,866.30	21.20
BLUEBERRY	2,866.67	4,779.33	1,420.70	172.60	114.40	121.49	80.52	7,646.00	10.47	18.68	2,748.50	21.60
BRASSEY	5,855.56	5,567.22	2,858.80	1.70	-	0.59	-	11,423.00	18.02	23.89	(7,669.00)	-
DAWSON	1,302.56	2,293.66	6,502.00	100.80	15.00	15.50	2.31	3,597.00	6.31	3.04	10,220.20	271.70
GRAHAM	5,511.00	5,408.20	7,232.80	262.90	112.10	36.35	15.50	10,919.00	6.64	7.44	8,942.30	40.70
GROUNDBIRCH_NORTH	2,284.17	3,837.51	4,374.60	37.20	-	8.50	-	6,122.00	7.99	8.44	2,406.20	21.80
GROUNDBIRCH_SOUTH	3,856.76	3,501.00	3,349.60	22.30	-	6.66	-	7,358.00	8.42	12.67	(1,933.40)	2.60
GUNDY	3,500.00	4,616.75	4,740.00	137.90	34.10	29.09	7.19	8,117.00	6.95	8.75	5,872.40	51.10
KOBES	4,013.00	7,559.43	5,778.00	104.70	-	18.12	-	11,572.00	7.13	10.84	458.50	11.20
LILY	3,112.50	7,229.33	3,668.40	38.70	-	-	-	10,342.00	15.91	7.76	(2,497.30)	2.10
NIG	1,855.78	3,061.00	3,008.20	160.60	51.30	53.39	17.05	4,917.00	8.72	7.43	4,112.10	38.10
PARKLAND	1,764.93	4,023.00	6,624.30	182.00	30.00	27.47	4.53	5,788.00	6.66	4.50	9,282.70	117.00
SEPTIMUS	2,225.37	3,284.37	4,937.90	353.80	78.80	71.65	15.96	5,509.00	7.11	4.68	13,386.60	157.70
SWAN	2,355.00	3,405.78	5,545.10	49.90	-	9.00	-	5,761.00	6.98	5.91	3,399.20	33.80
Swan-North	1,861.59	3,426.91	6,184.50	91.80	15.70	14.84	2.54	5,289.00	6.70	4.71	6,288.00	64.20
Sunset-Sunrise	1,607.56	3,817.85	5,526.90	161.90	45.40	29.29	8.21	5,426.00	7.23	5.01	7,010.60	67.20
Sundown	2,533.73	3,123.17	4,591.00	6.40	-	1.39	-	5,657.00	7.44	7.33	831.20	15.30
TOWN	2912	4125	5365.7	174.6	19.5	32.5	3.6	7037	7.3	6.6	6763	52.1

Table 39- Economic information (ROR, PV10) –after adjustments(multiplying the initial production by B12 adjustment ration –by area

	Estimated Drilling Costs (K$)	Completion Costs (K$)	Gas(MMcf)	Liquid (Mbbl)	Condensate (Mbbl)	Liqiuid yield(bbl/MMcf)	Condensate yield(bbl/MMcf)	Capital cost(M$C)	Op. Cost($/BOE)	Cap. Cost($/BOE)	PV10 ($)	ROR(%)
ALTARES	4,500.00	4,000.00	4,233.40	29.50	-	6.97	-	8,500.00	8.09	11.56	(940.20)	7.10
BLAIR	3,000.00	3,500.00	-	-	-	-	-	-	-	-	-	-
BLUEBERRY	2,900.00	3,000.00	2,099.30	255.00	169.00	121.47	80.50	5,900.00	8.90	9.75	8,423.10	99.20
BRASSEY	4,500.00	4,000.00	4,653.70	2.80	-	0.60	-	8,500.00	12.56	10.92	(2,417.00)	-
DAWSON	1,300.00	2,300.00	9,601.20	148.80	22.10	15.50	2.30	3,600.00	5.73	2.06	16,309.00	Greater than 500
GRAHAM	4,500.00	4,000.00	7,809.90	283.80	121.10	36.34	15.51	8,500.00	5.36	6.51	12,747.40	82.80
GROUNDBIRCH_NORTH	2,000.00	3,500.00	6,115.80	51.90	-	8.49	-	5,500.00	7.21	5.13	3,676.80	33.00
GROUNDBIRCH_SOUTH	3,000.00	3,500.00	4,355.70	29.00	-	6.66	-	6,500.00	7.80	8.61	249.20	11.10
GUNDY	3,000.00	3,000.00	4,767.90	138.70	34.30	29.09	7.19	6,000.00	6.93	6.43	8,054.10	115.30
KOBES	3,500.00	3,500.00	5,756.50	104.30	-	18.12	-	7,000.00	7.15	6.58	4,972.20	38.90
PARKLAND	1,700.00	3,000.00	10,264.70	282.00	46.50	27.47	4.53	4,700.00	5.59	2.36	17,941.20	Greater than 500
SEPTIMUS	3,000.00	2,000.00	8,416.70	603.10	134.20	71.66	15.94	5,000.00	5.96	2.49	26,263.90	Greater than 500
SWAN	2,300.00	3,200.00	8,603.00	77.40	-	9.00	-	5,500.00	6.31	3.64	8,066.00	91.40
Swan-North	1,900.00	3,000.00	8,586.80	127.40	21.80	14.84	2.54	4,900.00	6.23	3.14	10,697.60	143.10
Sunset-Sunrise	1,600.00	3,500.00	6,708.90	196.50	55.20	29.29	8.23	5,100.00	6.81	3.88	9,744.50	114.80
TOWN	2,900.00	3,000.00	6,087.80	198.10	22.10	32.54	3.63	5,900.00	6.99	4.87	9,456.50	102.70

Table 39 summarizes the major economic inputs and results for the development well economics by area. Fig. 47 and Fig. 48 are the maps of the ROR and PV10. You will see that in the fields such as Altares, in which the capital cost is high, the ROR is low. However, in fields such as Parkland and Septimus, the capital cost is lower and the rate of return is higher.

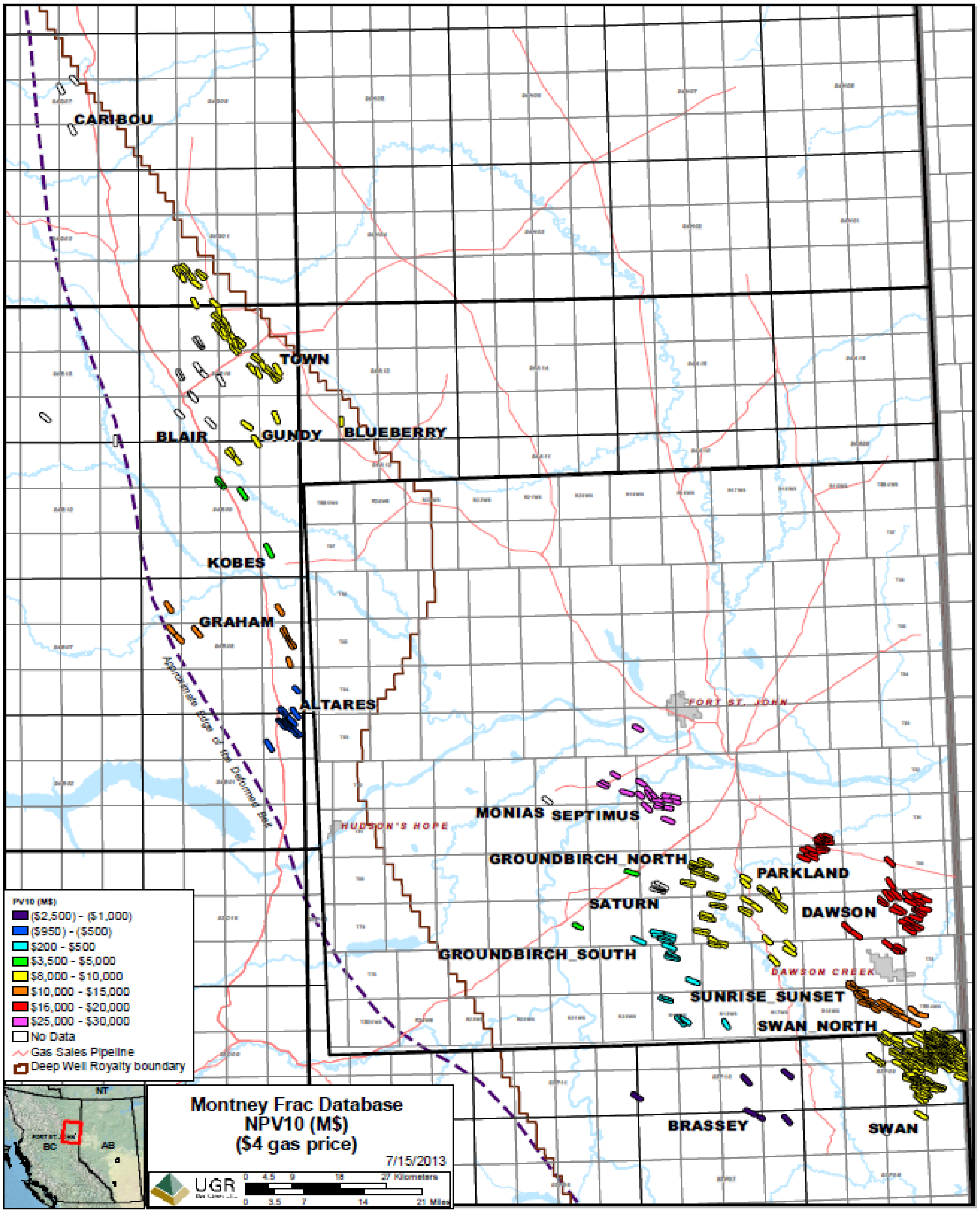


Fig. 47- Present value (PV10 M$) - Montney fields

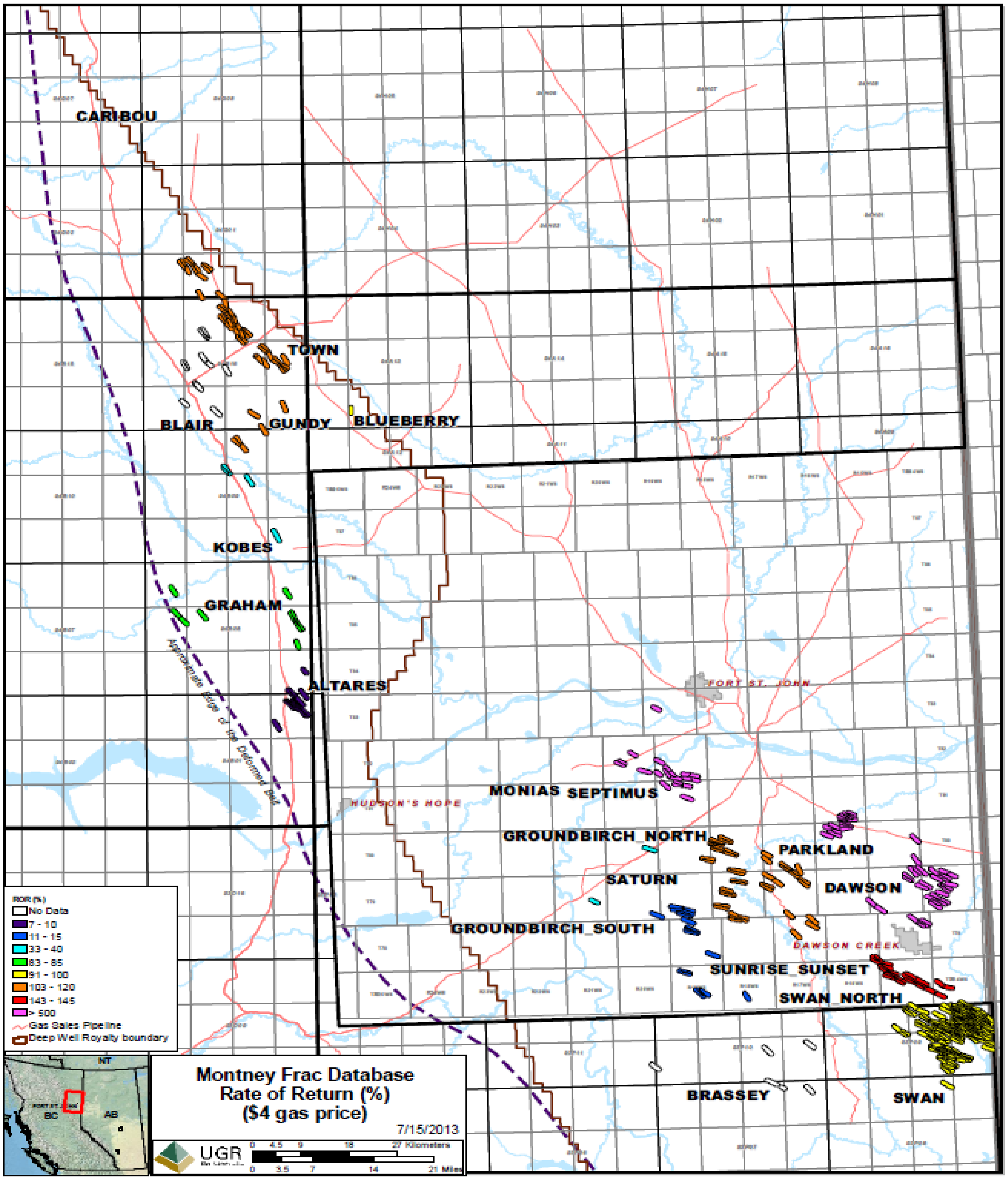


Fig. 48- Rate of return (ROR) - Montney fields

5. CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

In this research, we performed multivariate regression to analyze the impact of completion parameters on the best year production (B12). To represent the uncertainty associate in each model Monte Carlo simulations were performed on the multivariate regression output. In addition, after developing the best model for predicting the B12 of slickwater wells, by using the type curves, we computed ROR and PV10. The points we want to mention as the results of our research are:

- Starting in 2009, slickwater fracture treatments have increased steadily and become a common practice in the Montney formation in British Columbia.
- Multivariate regression analysis is a useful tool to study the effect of different completion parameters on production rate.
- Multivariate analysis shows the number of fracture stages and perforation clusters per stage have the greatest impact on B12.
- Additional sand for slickwater wells improves the production, but the uncertainty is high.
- Completed lateral length and fracture fluid volume do not show a strong correlation with well performance for slickwater wells. For some energized fracture fluid systems, they have positive correlation.
- The best model for predicting B12 is the model with completion parameters per stage.

- The best formula to predict the B12 for slickwater wells is:

$$B12 = 0.03 \times LL/Stage + 169 \times FS + 284 \times PC/Stage + 0.11 \times Fluid/Stage$$

5.2 Recommendation for Future Framework

- The Montney completion database should be expanded to include all wells in NE British Columbia and then re-evaluated with multivariate regression techniques.
- Injection rate should be included as an independent variable in the statistical analysis.

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APPENDIX A

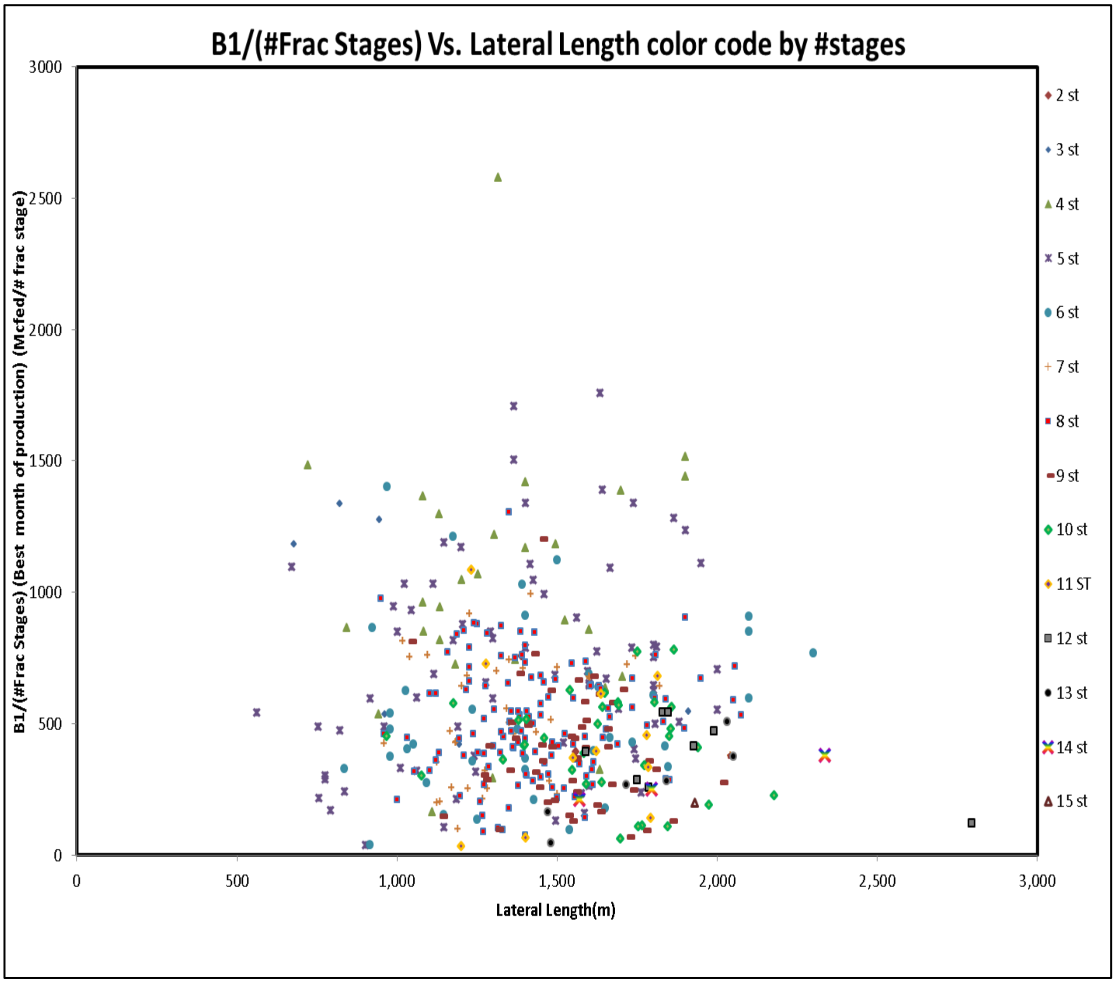


Fig. 49- B1/ (#Frac stages) vs. LL color code by #stages

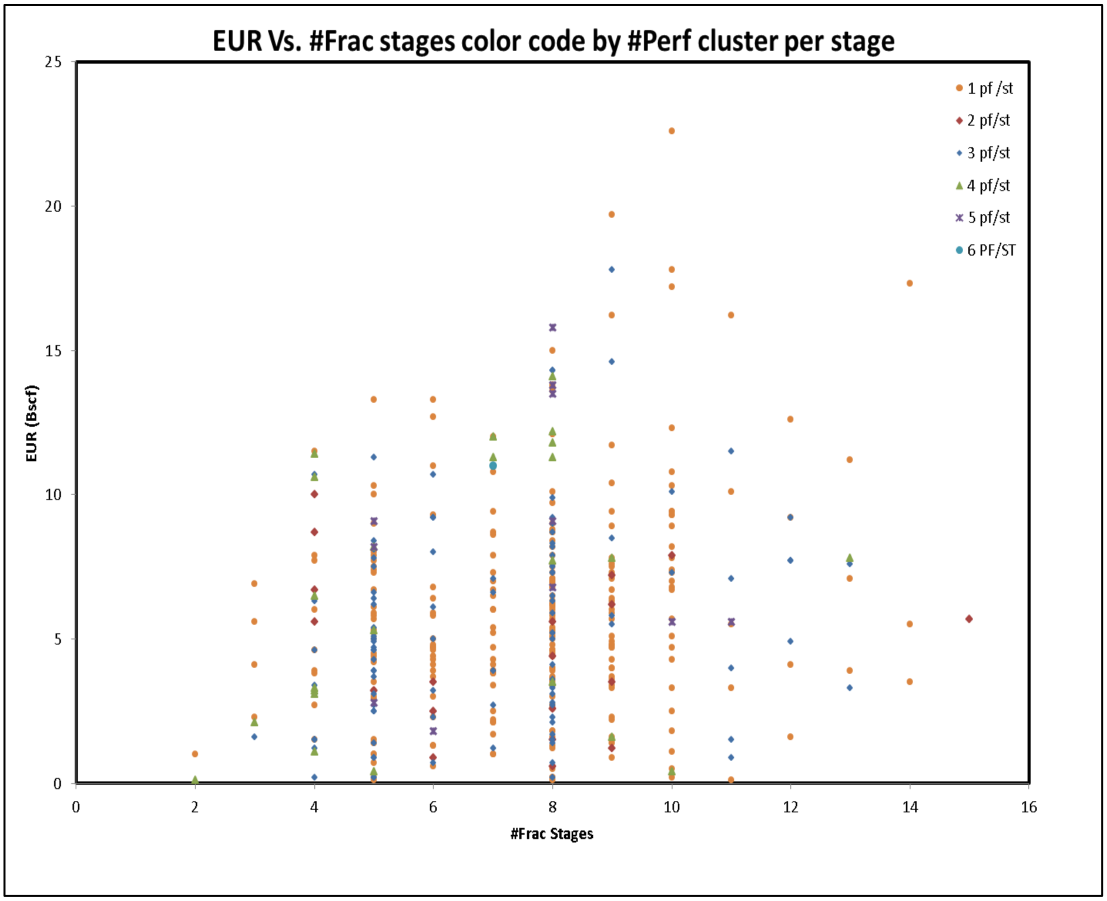


Fig. 50- EUR vs. #Frac stages color code by # perforation cluster per stage

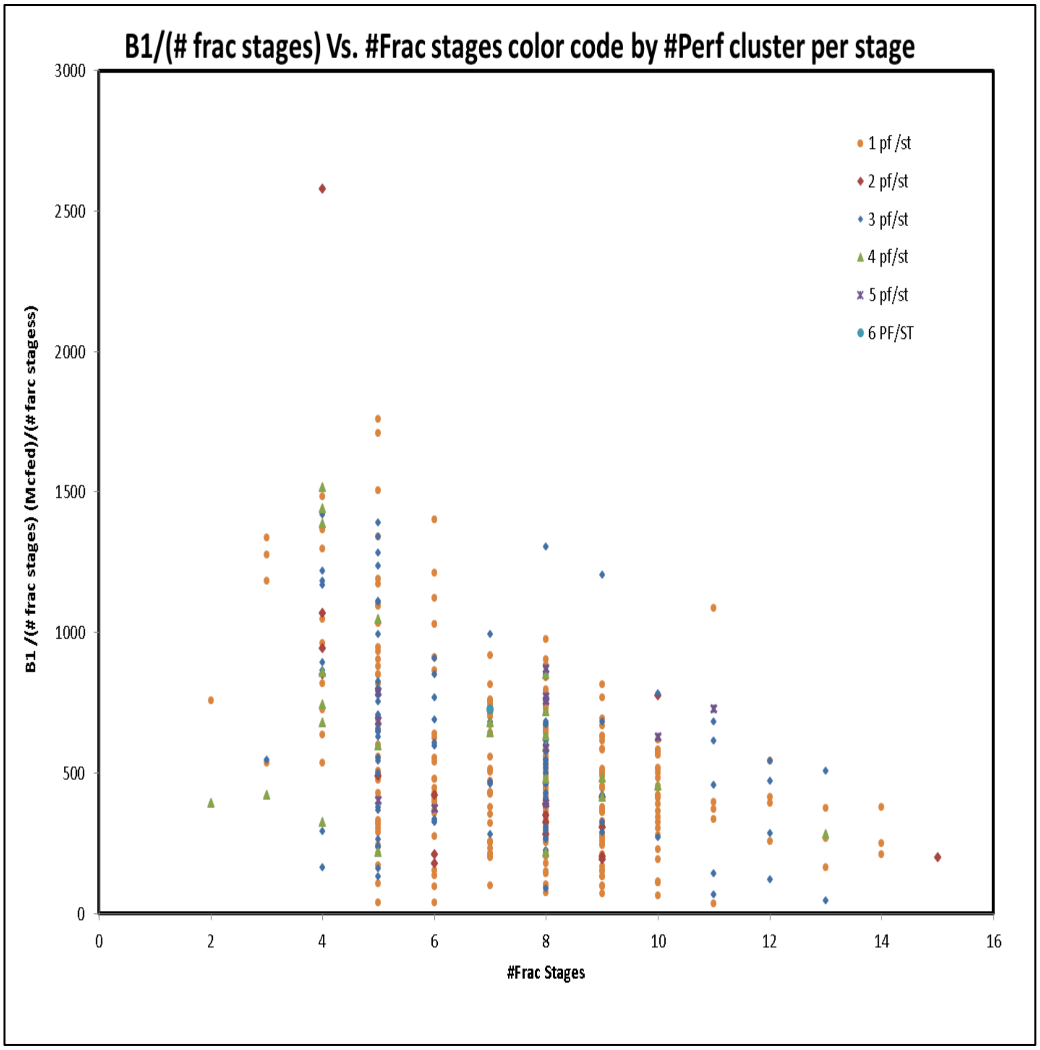


Fig. 51- B1/ (#Frac stages) vs. #Frac stages color code by perforation cluster per stage

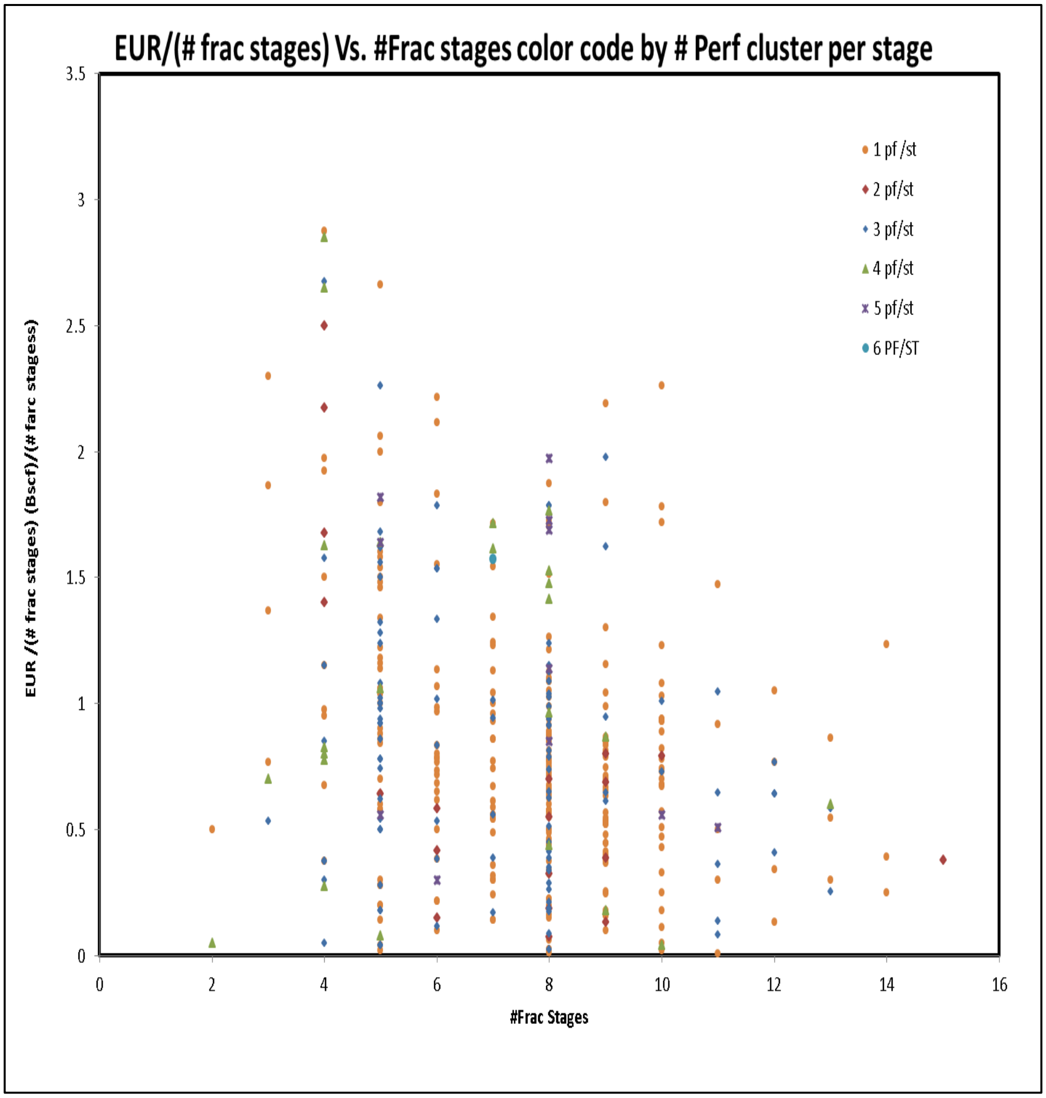


Fig. 52- EUR/ (#Frac stages) vs. #Frac stages color code by # perforation cluster per stage

SUMMARY OUTPUT								
Regression Statistics								
Multiple F	0.189332							
R Square	0.035847							
Adjusted I	0.024031							
Standard I	1166.144							
Observati	414							
ANOVA								
	df	*SS*	*MS*	*F*	*gnificance F*			
Regressio	5	20628394	4125679	3.033831	0.010585			
Residual	408	5.55E+08	1359891					
Total	413	5.75E+08						
	Coefficients	*andard Err*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*ower 95.0%*	*pper 95.0%*
Intercept	830.6135	602.2865	1.3791	0.168619	-353.358	2014.585	-353.358	2014.585
LL/PI	0.389052	0.421454	0.923118	0.356491	-0.43944	1.217544	-0.43944	1.217544
FS	103.2205	31.97892	3.227767	0.001348	40.35647	166.0845	40.35647	166.0845
PC	218.3623	103.7439	2.10482	0.035918	14.42295	422.3017	14.42295	422.3017
Fluid/PI	-0.06418	0.043427	-1.47779	0.140236	-0.14954	0.021193	-0.14954	0.021193
Sand/PI	3.18662	3.178881	1.002435	0.316728	-3.06241	9.435649	-3.06241	9.435649

Fig. 53-Output summary –all data –LL/pi, FS, PC, Sand/PI

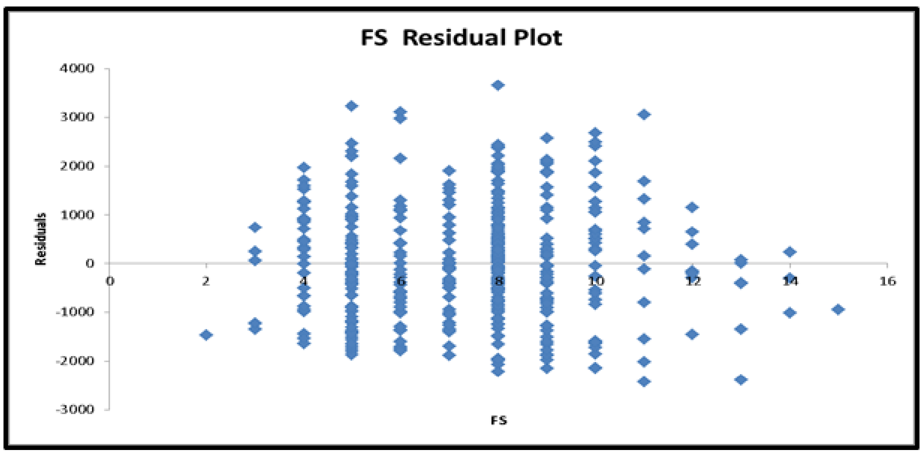


Fig. 54-FS residual plot - all data –LL/pi, FS, PC, Sand/PI

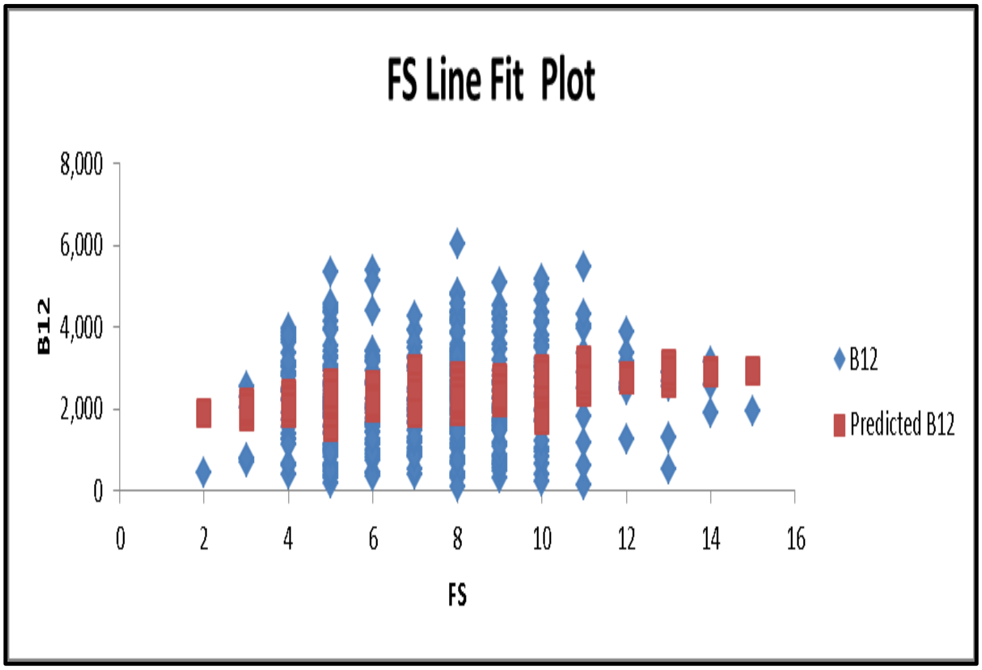


Fig. 55- FS fit plot - all data –LL/pi, FS, PC, Sand/PI

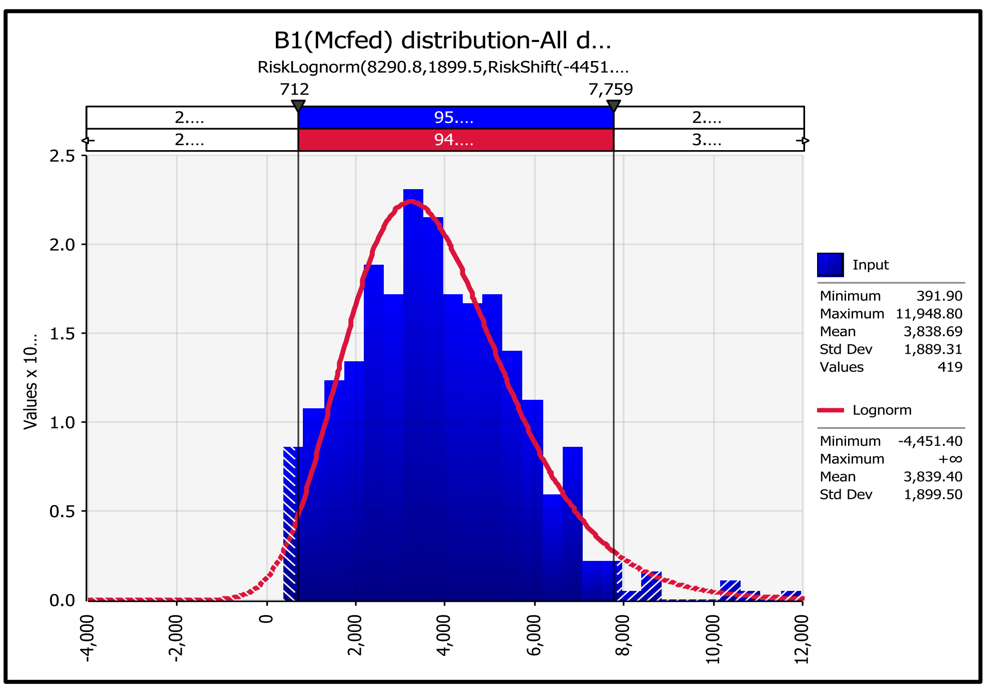


Fig. 56- B1 distribution (All data)

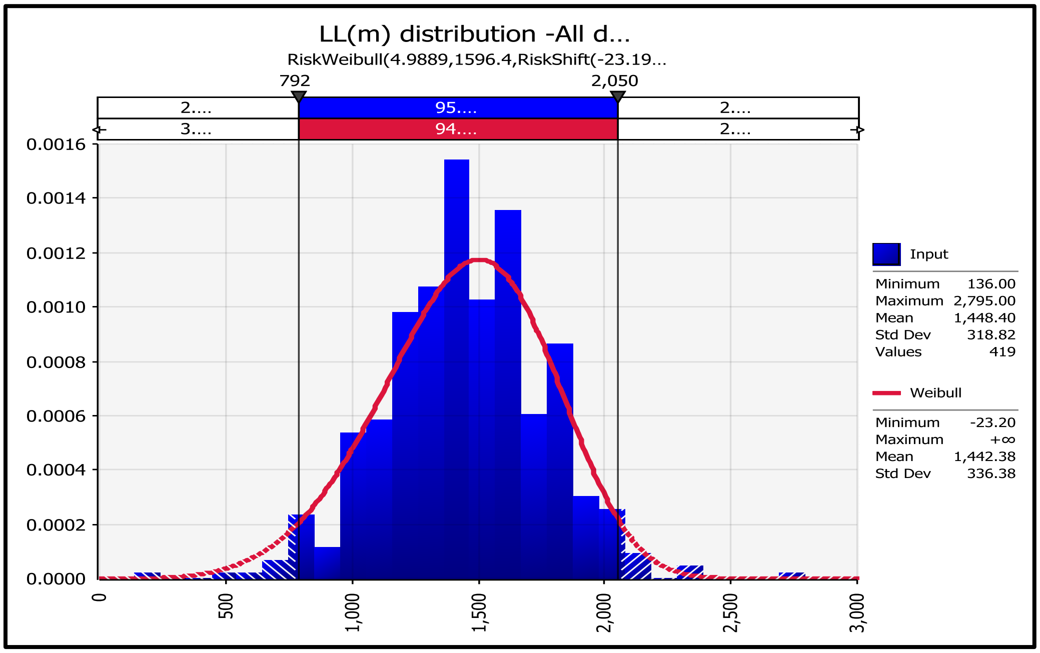


Fig. 57- Lateral length distribution (All data)

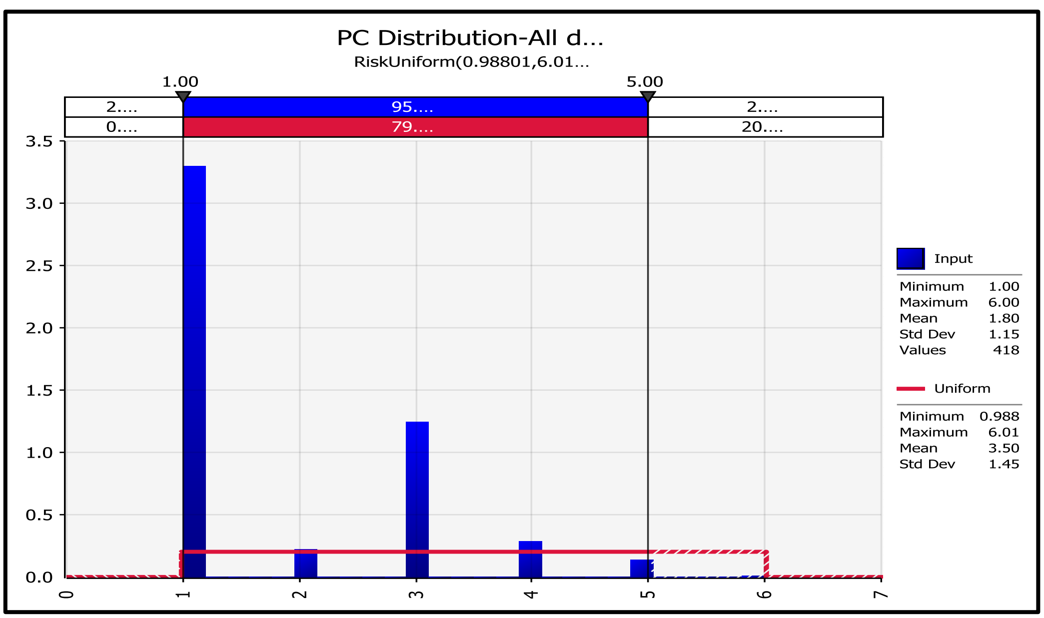


Fig. 58-Perforation cluster distribution

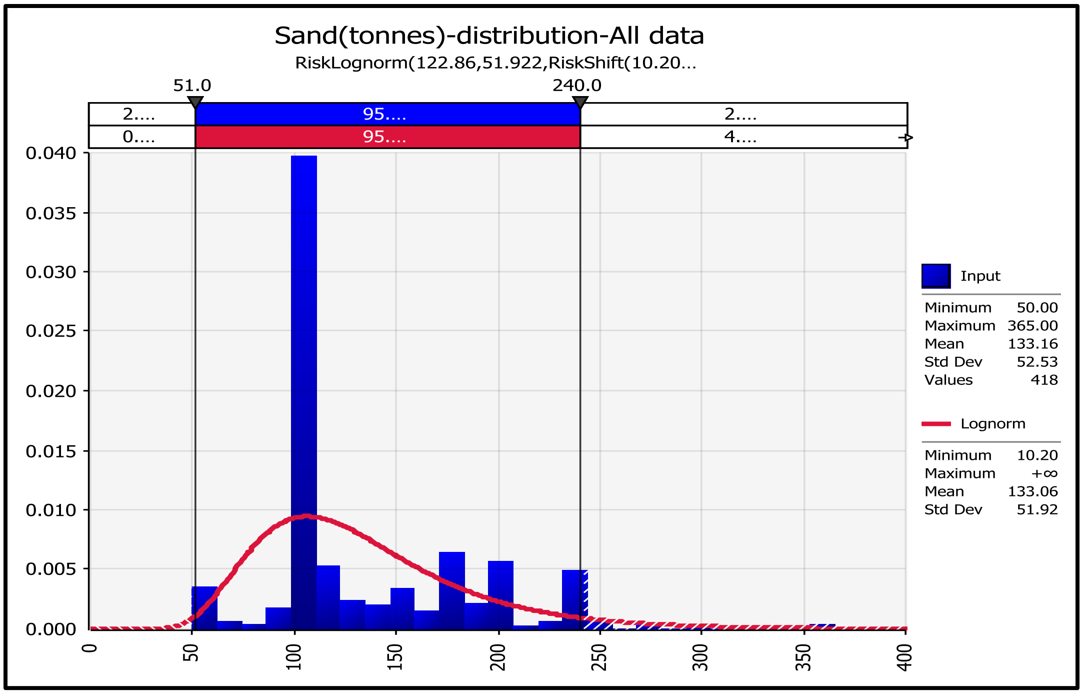


Fig. 59- Sand distribution

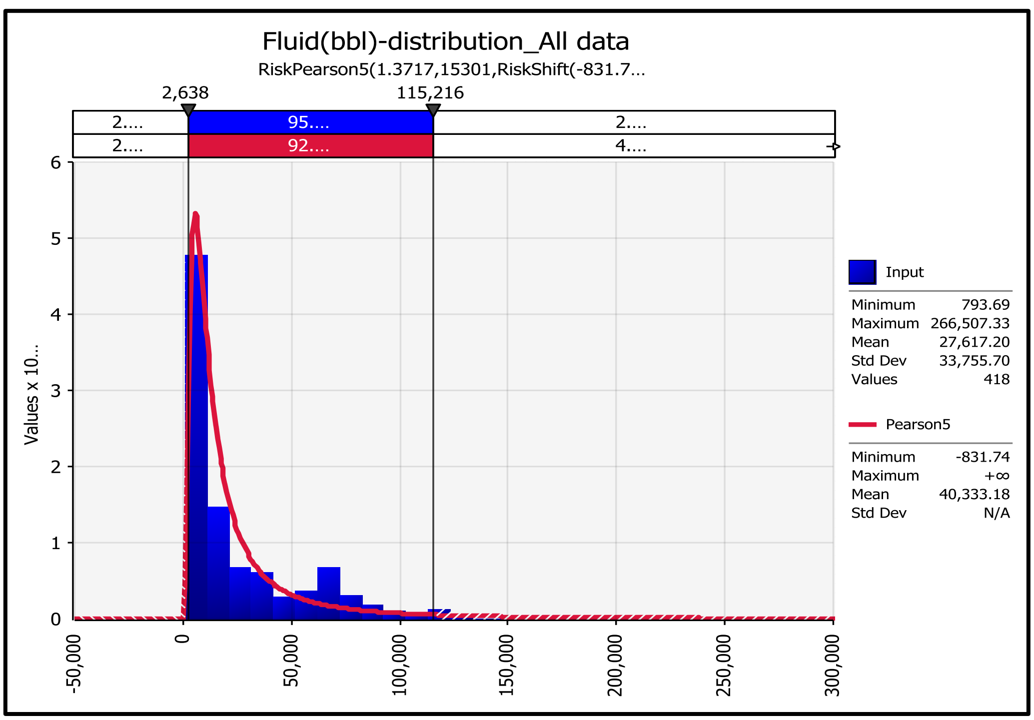


Fig. 60-Fluid distribution

Monte Carlo simulation-All Correlation Charts for LL, FS, PC, Fluid

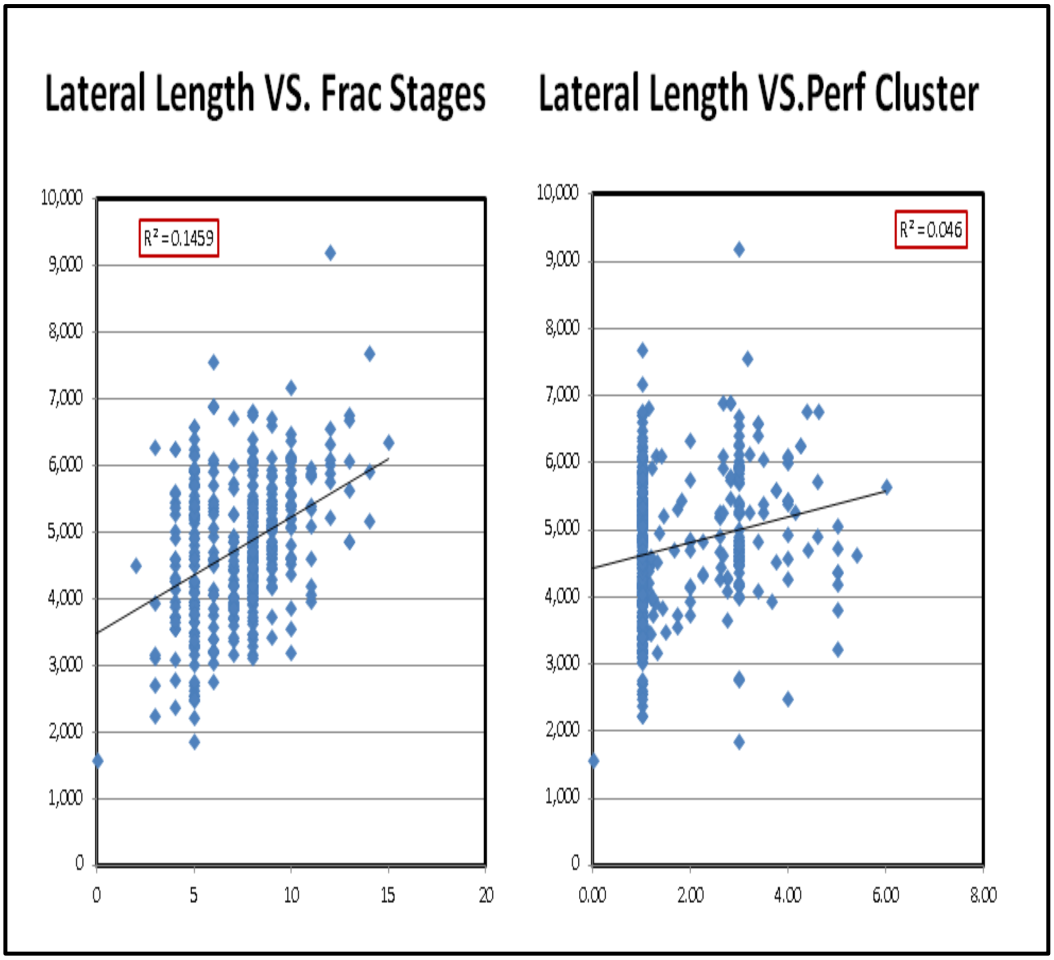


Fig. 61-Lateral length vs. FS and PC

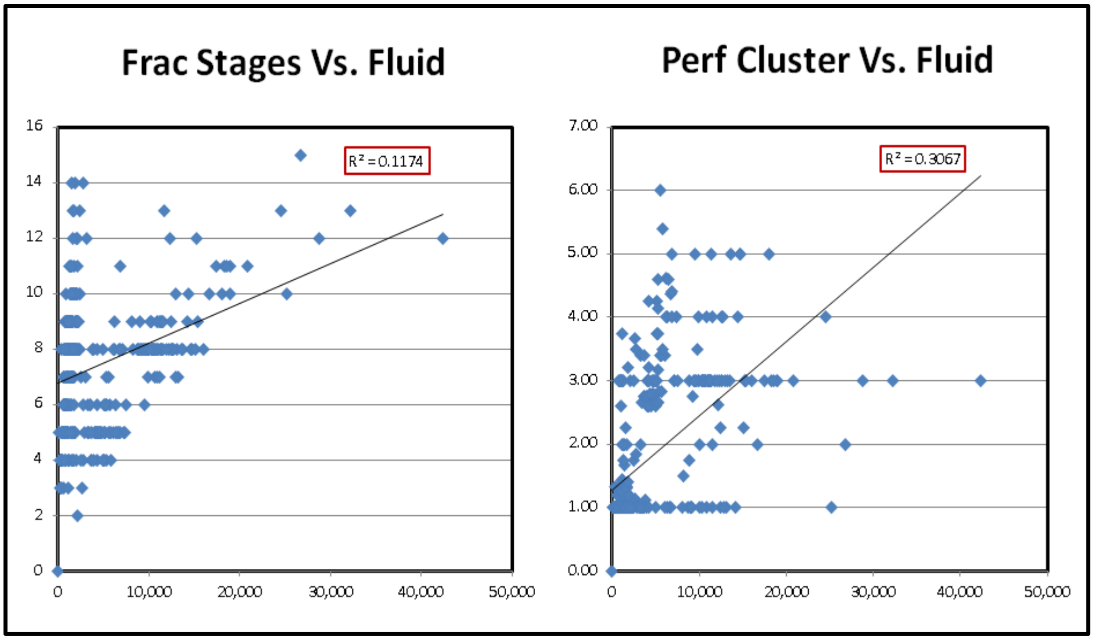


Fig. 62-Perforation cluster and fracture stages vs. fluid

Monte Carlo simulation-All Correlation Charts for LL, FS, PC, Fluid

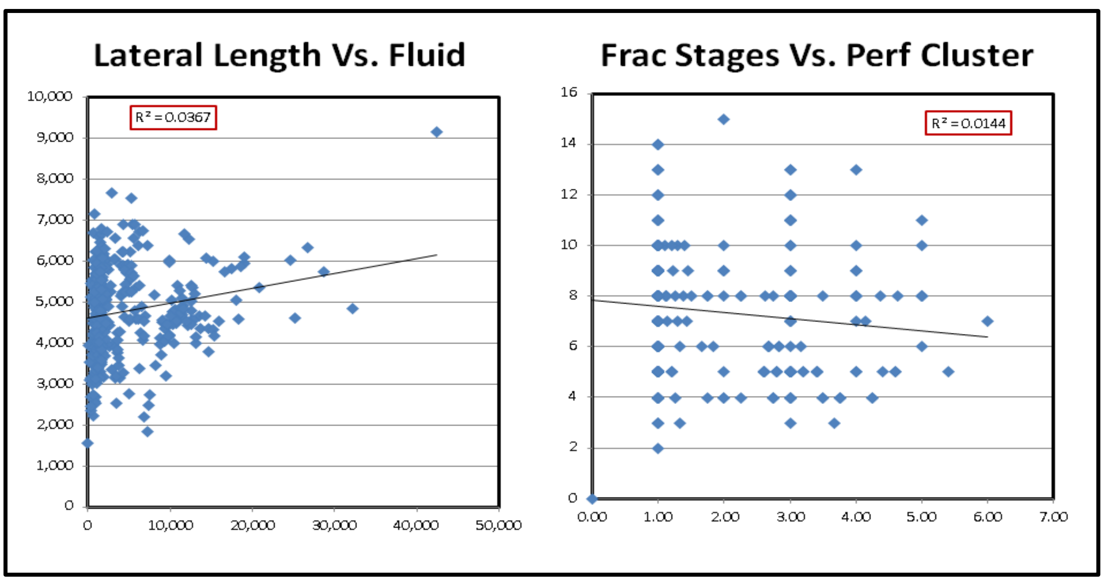


Fig. 63-Lateral length vs. fluid, Frac stages vs. perforation cluster

Correlation Matrix:

Using the square root of R^2 from above correlation charts:

@RISK Correlations	LL in B17	FS in B18	PC in B19	Fluid in B20
LL in B17	1			
FS in B18	0.38	1		
PC in B19	0.21	0.12	1	
Fluid in B20	0.19	0.34	0.61	1

Fig. 64-Correlation matrix –first and second model

SUMMARY OUTPUT						
Regression Statistics						
Multiple R	0.906275					
R Square	0.821335					
Adjusted R Square	0.808847					
Standard Error	1104.937					
Observations	127					
ANOVA						
	df	*SS*	*MS*	*F*	*Significance F*	
Regression	4	6.9E+08	1.73E+08	141.3599	8.04814E-45	
Residual	123	1.5E+08	1220886			
Total	127	8.41E+08				
	Coefficients	*Standard Err*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A
LL	0.004875	0.079678	0.061188	0.951308	-0.152841777	0.162592494
FS	228.9871	61.94883	3.696391	0.000328	106.3631947	351.6110109
PC/Stage	276.201	89.76072	3.07708	0.002577	98.52511476	453.8768059
Fluid	-0.02846	0.024472	-1.16286	0.247137	-0.076898463	0.019983299

Fig. 65- Summary output – LL, FS, PC, intercept= 0

Variance Multiplier	1.5 LL,1.7 FS,PC,FLUID			
# Negative B12	3.20%	Auto Iteration(13000 data)		
Match percentage	95			
LL Coeffs Dist.	Risk Normal			
FS Coeff Dist.	Risk Normal			
PC Coeffs Dist.	Risk Normal			
Fluid Coeff Dist.	Risk Normal			
LL	RiskLoglogistic	Using Corr matrix between LL,FS,Fluid ,PC	Truncat e in the range of Min and Max	Fit the dist
FS	RiskBinomial	Using Corr matrix between LL,FS,Fluid ,PC	Truncat e in the range of Min and Max	Fit the dist
PC	RiskNormal	Using Corr matrix between LL,FS,Fluid ,PC	Truncat e in the range of Min and Max	Fit the dist
Fluid	RiskLoglogistic	Using Corr matrix between LL,FS,Fluid ,PC	Truncate e in the range of Min and Max	Fit the dist.

Fig. 66-Summary table – LL, FS, PC, intercept= 0

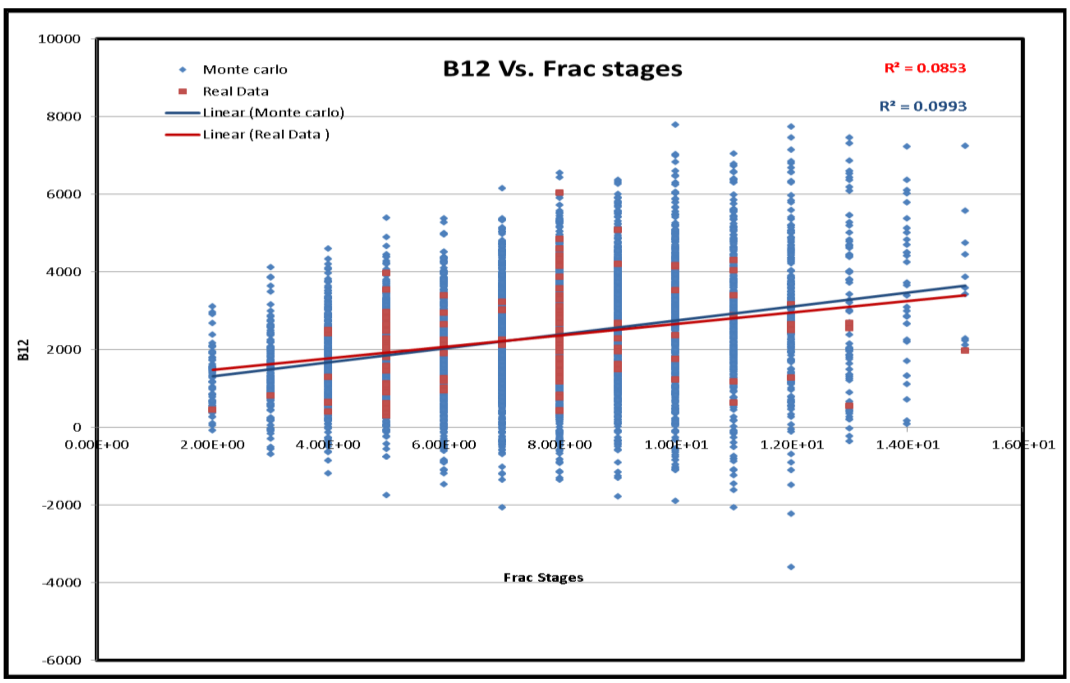


Fig. 67- B12 vs. Frac stages - LL, FS, PC, intercept= 0

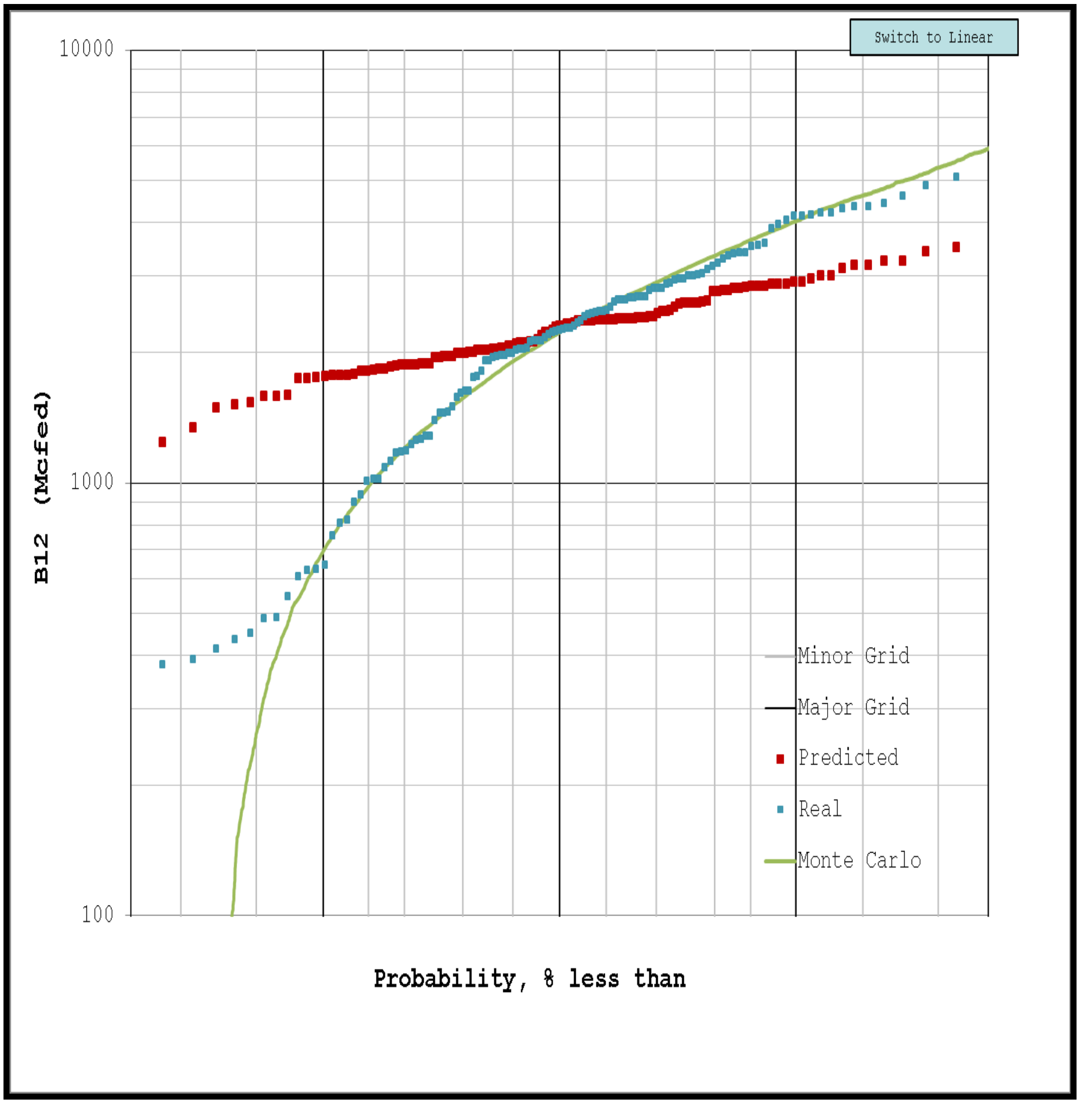
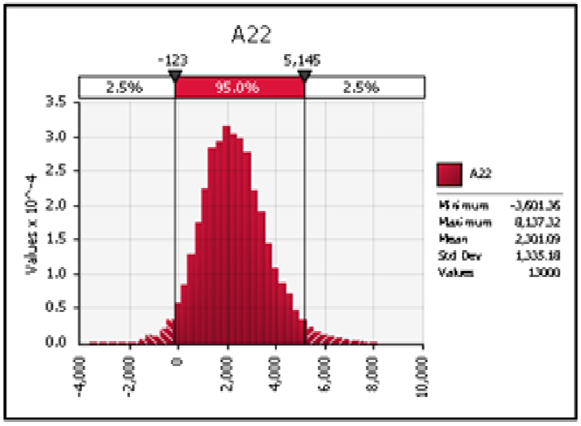
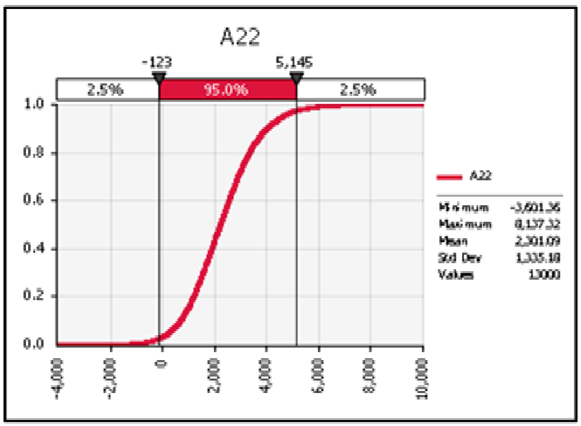
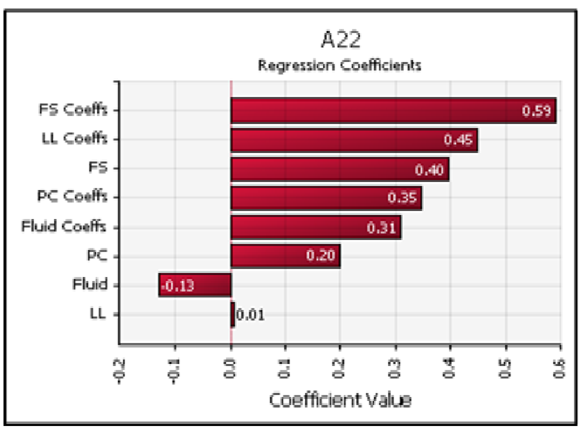


Fig. 68- Probability plot – LL, FS, PC, intercept= 0







Simulation Summary Information	
Workbook Name	B12-Slickwater 5 - Copy.xl
Number of Simulations	1
Number of Iterations	13000
Number of Inputs	8
Number of Outputs	1
Sampling Type	Latin Hypercube
Simulation Start Time	4/11/13 12:27:33
Simulation Duration	00:00:10
Random # Generator	Mersenne Twister
Random Seed	1220241513

Summary Statistics for B12			
Statistics		Percentile	
Minimum	-3601.363112	5%	263.4007087
Maximum	8137.318862	10%	695.6278304
Mean	2301.088809	15%	981.2770699
Std Dev	1335.183405	20%	1205.130279
Variance	1782714.726	25%	1392.029697
Skewness	0.358140221	30%	1569.22788
Kurtosis	3.540044491	35%	1737.387067
Median	2225.32753	40%	1907.516532
Mode	2044.724	45%	2059.785144
Left X	-122.7950497	50%	2225.32753
Left P	3%	55%	2395.71234
Right X	5144.507903	60%	2554.790268
Right P	98%	65%	2729.730385
Diff X	5267.302952	70%	2903.827728
Diff P	95%	75%	3112.787629
#Errors	0	80%	3342.786089
Filter Min	Off	85%	3643.722239
Filter Max	Off	90%	4019.556281
#Filtered	0	95%	4609.188108

Regression and Rank Information for B12			
Rank	Name	Regr	Corr
1	FS Coeffs	0.590	0.568
2	LL Coeffs	0.448	0.441
3	FS	0.398	0.312
4	PC Coeffs	0.347	0.346
5	Fluid Coeffs	0.310	0.294
6	PC	0.198	0.205
7	Fluid	-0.130	0.181
8	LL	0.006	0.098

Fig. 69- Tornado chart – LL, FS, PC, intercept= 0

Regression Statistics						
Multiple R	0.370486					
R Square	0.13726					
Adjusted R Square	0.108973					
Standard Error	1105.458					
Observations	127					
ANOVA						
	df	*SS*	*MS*	*F*	*Significance F*	
Regression	4	23719595	5929899	4.852467	0.001149629	
Residual	122	1.49E+08	1222038			
Total	126	1.73E+08				
	Coefficients	*andard Err*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	578.614	614.0772	0.94225	0.347927	-637.013147	1794.241
LL	-0.06209	0.10222	-0.6074	0.544712	-0.264444255	0.140266
FS	200.1339	69.87309	2.864248	0.004923	61.81309512	338.4546
PC	248.8203	95.06786	2.617291	0.009984	60.623935	437.0166
Fluid	-0.02144	0.025688	-0.83476	0.405485	-0.072293973	0.029408

Fig. 70- Output summary- LL, FS, PC, intercept ≠ 0

Variance Multiplier	1.2			
# Negative B12	3.45%	Auto Iteration(19200 data)		
Match percentage	93			
Intercept Dist.	Risk Normal			
LL Coeff Dist.	Risk Normal			
FS Coeff Dist.	Risk Normal	Risk truncate(0)		
PC Coeffs Dist.	Risk Normal	Risk truncate(0)		
Fluid Coeff Dist.	Risk Normal			
LL	RiskLoglogistic	Using Corr matrix between LL,FS,Fluid ,PC	Truncat e in the range of Min and Max	Fit the dist.
FS	RiskBinomial	Using Corr matrix between LL,FS,Fluid ,PC	Truncate e in the range of Min and Max	Fit the dist.
PC	RiskNormal	Using Corr matrix between LL,FS,Fluid ,PC	Truncate e in the range of Min and Max	Fit the dist.
Fluid	RiskLoglogistic	Using Corr matrix between LL,FS,Fluid ,PC	Truncate e in the range of Min and Max	Fit the dist.

Fig. 71- Summary table – LL, FS, PC, intercept ≠ 0

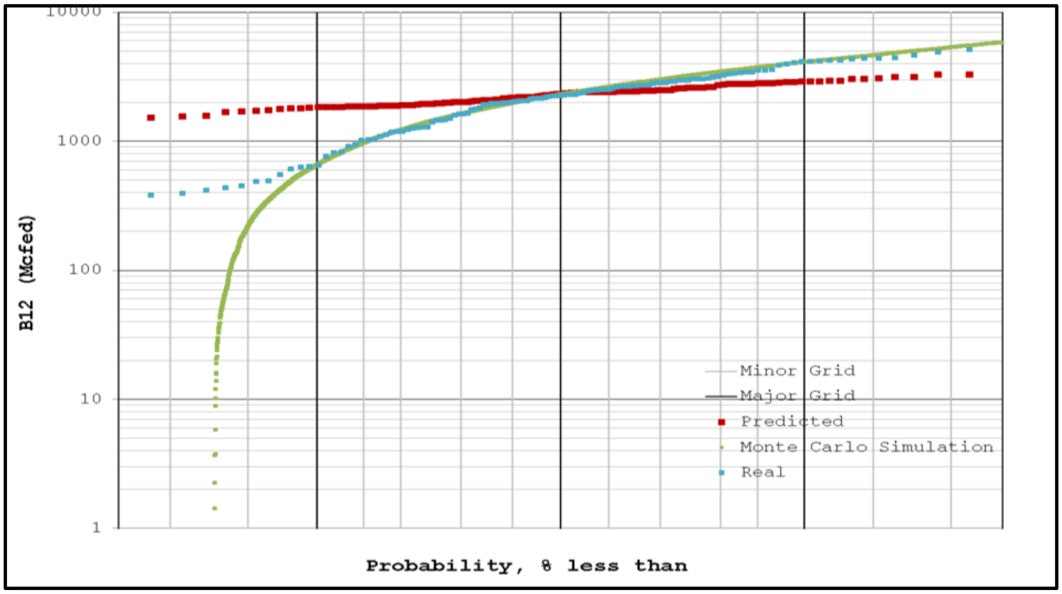


Fig. 72- Probability plot- LL, FS, PC, intercept ≠ 0

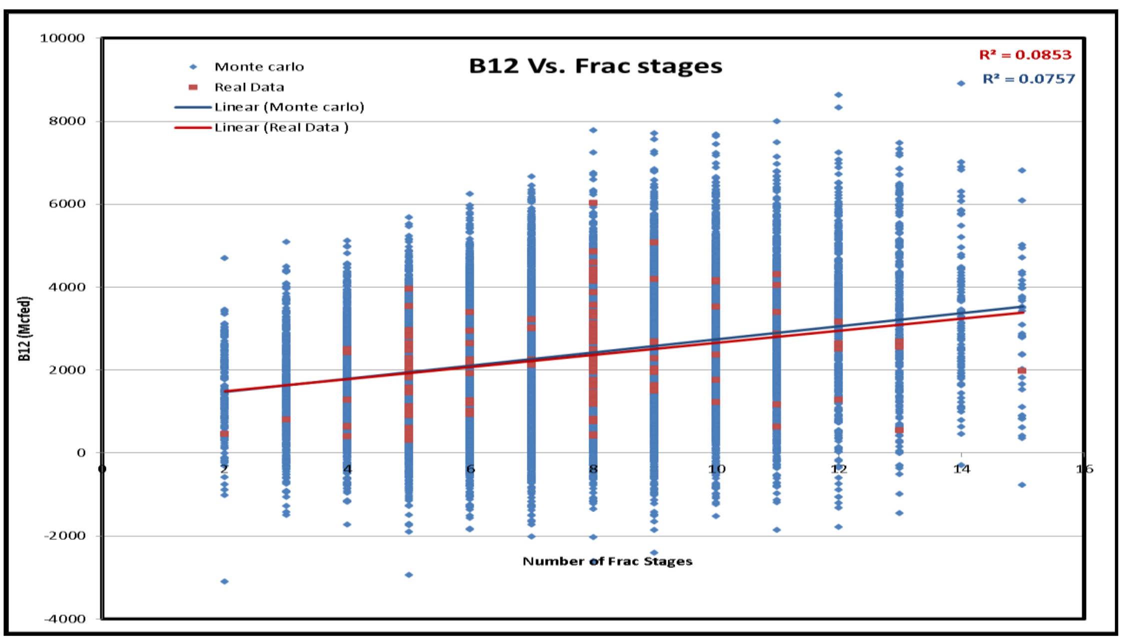
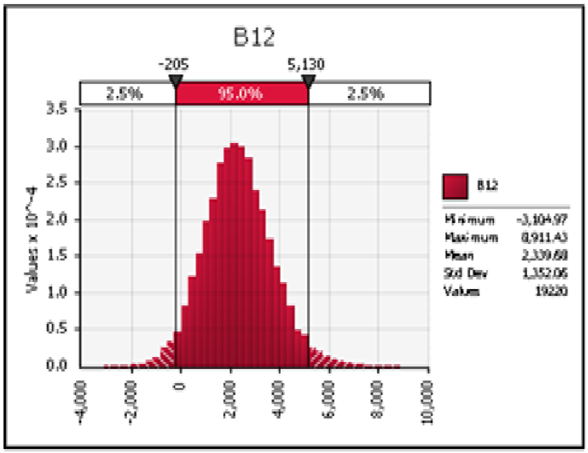
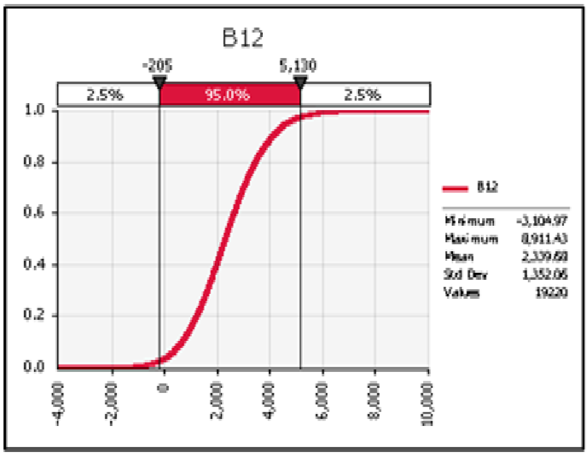
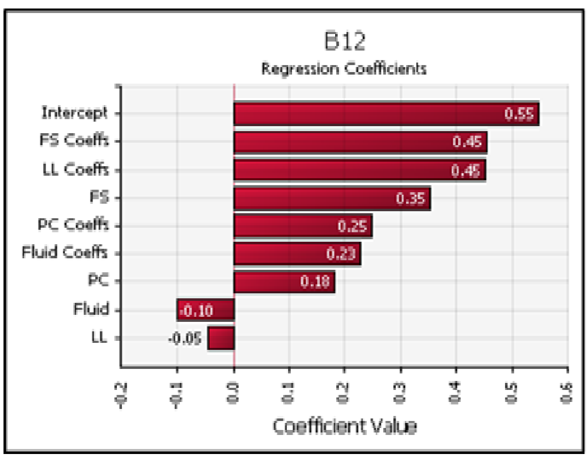


Fig. 73- B12 vs. Frac stages- LL, FS, PC, intercept ≠ 0







Simulation Summary Information	
Workbook Name	B12-Slickwater 7.xlsm
Number of Simulations	1
Number of Iterations	19220
Number of Inputs	9
Number of Outputs	1
Sampling Type	Latin Hypercube
Simulation Start Time	4/3/13 11:26:27
Simulation Duration	00:00:40
Random # Generator	Mersenne Twister
Random Seed	1620720822

Summary Statistics for B12			
Statistics		Percentile	
Minimum	-3104.973756	5%	215.5591198
Maximum	8911.431777	10%	647.6409995
Mean	2339.684218	15%	965.2840062
Std Dev	1352.060166	20%	1208.045223
Variance	1828066.693	25%	1432.471657
Skewness	0.225789873	30%	1620.492557
Kurtosis	3.284302217	35%	1793.888732
Median	2293.07875	40%	1961.834053
Mode	2472.880422	45%	2130.197853
Left X	-205.0431011	50%	2293.07875
Left P	3%	55%	2459.090064
Right X	5129.576456	60%	2628.601734
Right P	98%	65%	2802.621816
Diff X	5334.619557	70%	2990.864033
Diff P	95%	75%	3210.492459
#Errors	0	80%	3443.620042
Filter Min	Off	85%	3716.463924
Filter Max	Off	90%	4082.447237
#Filtered	0	95%	4609.957998

Regression and Rank Information for B12			
Rank	Name	Regr	Corr
1	Intercept	0.547	0.541
2	FS Coeffs	0.454	0.436
3	LL Coeffs	0.452	0.443
4	FS	0.354	0.262
5	PC Coeffs	0.247	0.248
6	Fluid Coeffs	0.227	0.234
7	PC	0.181	0.175
8	Fluid	-0.100	0.150
9	LL	-0.047	0.038

Fig. 74- Tornado chart – LL, FS, PC, intercept ≠ 0

SUMMARY OUTPUT						
Regression Statistics						
Multiple R	0.374558					
R Square	0.140294					
Adjusted R Square	0.112107					
Standard Error	1103.513					
Observations	127					
ANOVA						
	df	*SS*	*MS*	*F*	*Significance F*	
Regression	4	24243909	6060977	4.977234	0.000945625	
Residual	122	1.49E+08	1217740			
Total	126	1.73E+08				
	Coefficients	*andard Err*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	1179.712	736.68	1.60139	0.111877	-278.6197134	2638.043529
LL/Stage	-0.57406	0.471309	-1.21801	0.22557	-1.507063204	0.358942962
FS	100.1718	60.19754	1.664052	0.098669	-18.99523096	219.3388521
PC/Stage	259.0539	96.30391	2.689963	0.008147	68.41071204	449.6971106
Fluid/Stage	0.006562	0.25038	0.026207	0.979135	-0.489090483	0.502214043

Fig. 75- Output summary- LL per stage, FS, PC per stage, fluid per stage, intercept ≠ 0

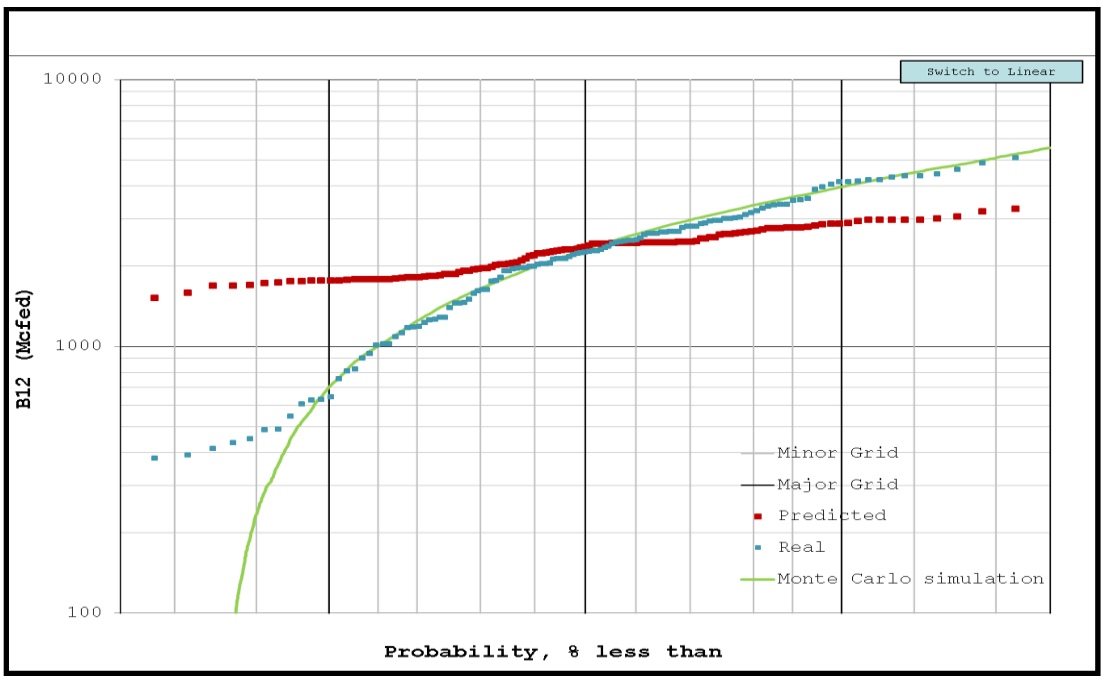


Fig. 76- Probability plot- LL per stage, FS, PC per stage, fluid per stage, intercept ≠ 0

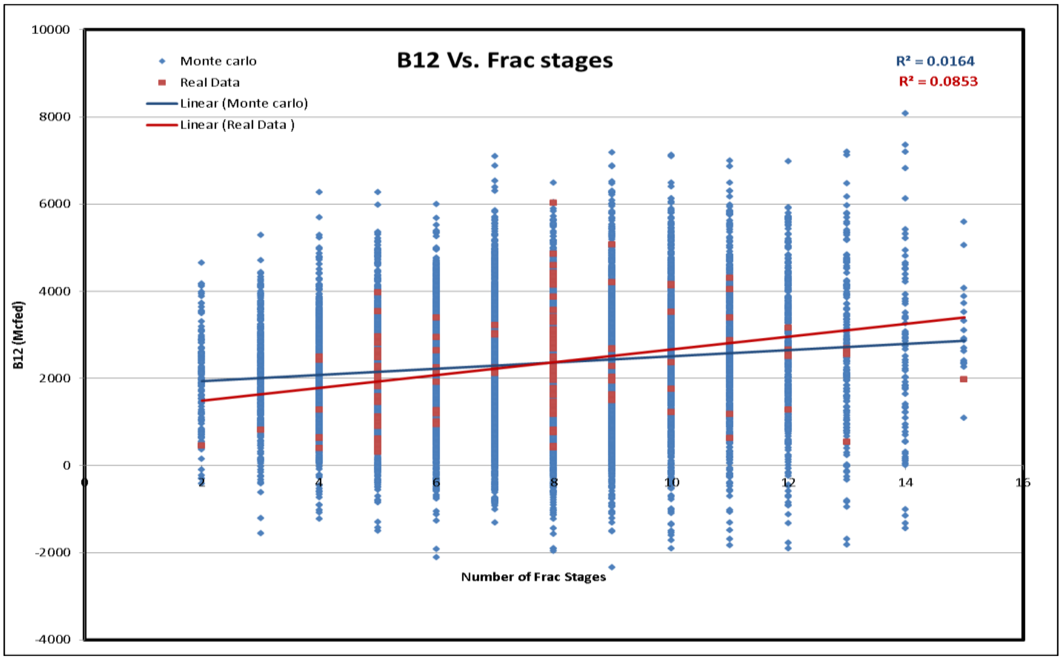
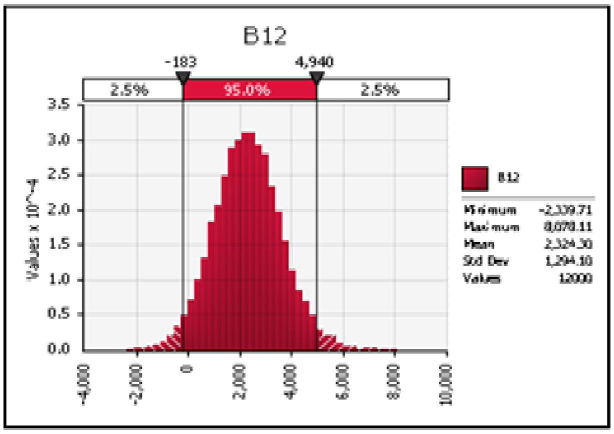
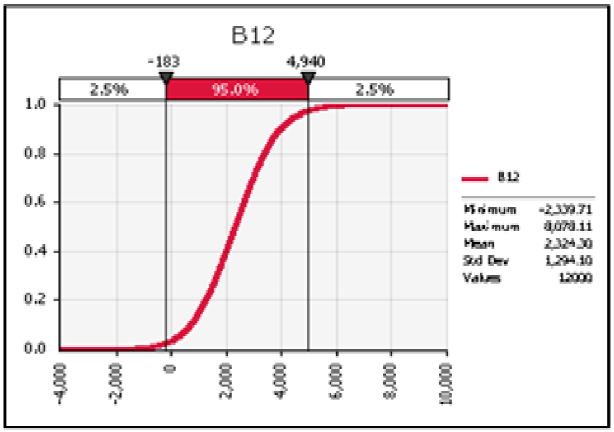
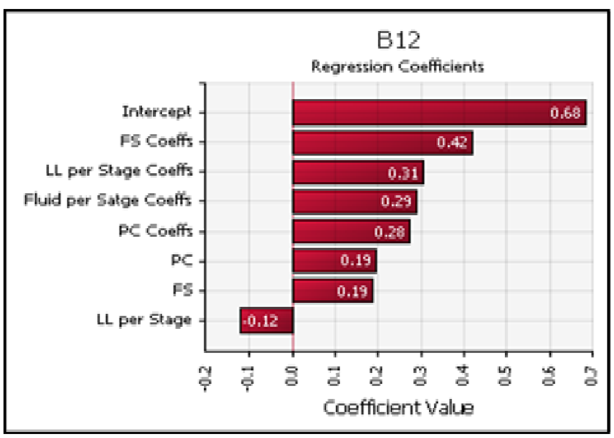


Fig. 77- B12 vs. Frac stages- LL per stage, FS, PC per stage, fluid per stage, intercept ≠ 0







Simulation Summary Information	
Workbook Name	B12-Slickwater-Fluid per s
Number of Simulations	1
Number of Iterations	12000
Number of Inputs	9
Number of Outputs	1
Sampling Type	Latin Hypercube
Simulation Start Time	4/12/13 13:13:12
Simulation Duration	00:00:09
Random # Generator	Mersenne Twister
Random Seed	1424380903

Summary Statistics for B12			
Statistics		Percentile	
Minimum	-2339.71339	5%	234.9228297
Maximum	8078.114739	10%	702.0205781
Mean	2324.29732	15%	1003.017745
Std Dev	1294.099311	20%	1246.561294
Variance	1674693.027	25%	1464.888368
Skewness	0.105949361	30%	1649.484867
Kurtosis	3.226981717	35%	1816.708205
Median	2307.896472	40%	1989.683705
Mode	2166.109115	45%	2151.667735
Left X	-183.1727863	50%	2307.896472
Left P	3%	55%	2470.013842
Right X	4940.36906	60%	2633.781407
Right P	98%	65%	2805.044124
Diff X	5123.541846	70%	2976.015775
Diff P	95%	75%	3160.750879
#Errors	0	80%	3382.297986
Filter Min	Off	85%	3630.084573
Filter Max	Off	90%	3961.9987
#Filtered	0	95%	4484.936484

Regression and Rank Information for B12			
Rank	Name	Regr	Corr
1	Intercept	0.684	0.669
2	FS Coeffs	0.420	0.404
3	LL per Stage Coef	0.306	0.284
4	Fluid per Satge C	0.291	0.289
5	PC Coeffs	0.276	0.272
6	PC	0.194	0.168
7	FS	0.188	0.120
8	LL per Stage	-0.121	0.043
9	Dataset 2	0.000	0.043254405

Fig. 78- Tornado chart – LL per stage, FS, PC per stage, fluid per stage, intercept ≠ 0

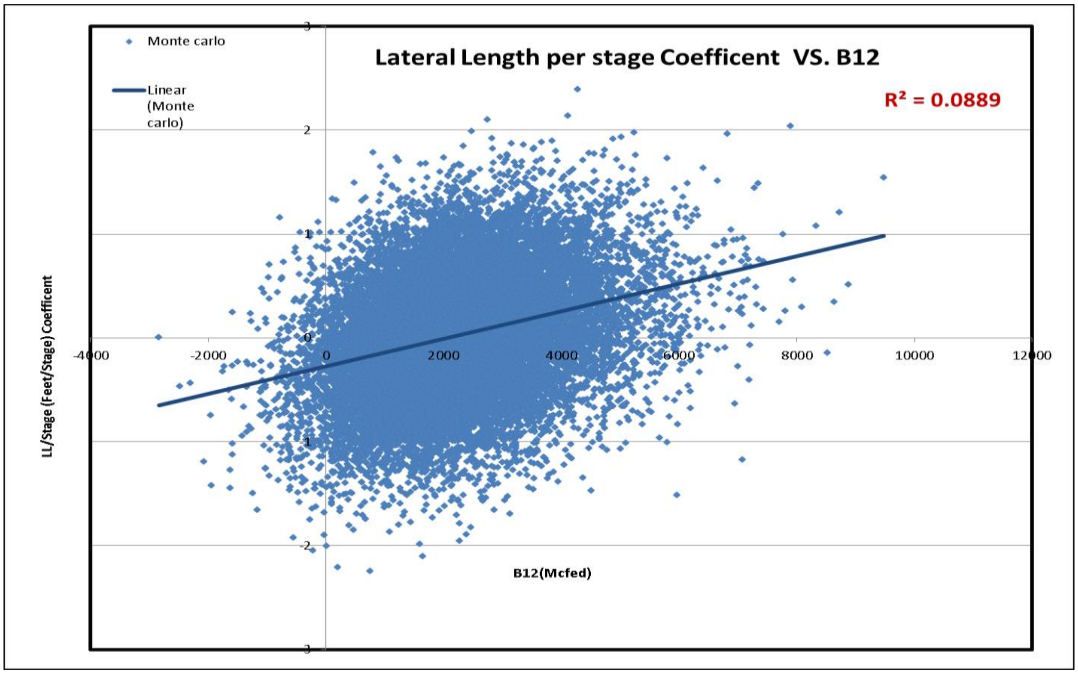


Fig. 79- LL per stage vs.B12- LL per stage, FS, PC per stage, fluid per stage, intercept = 0

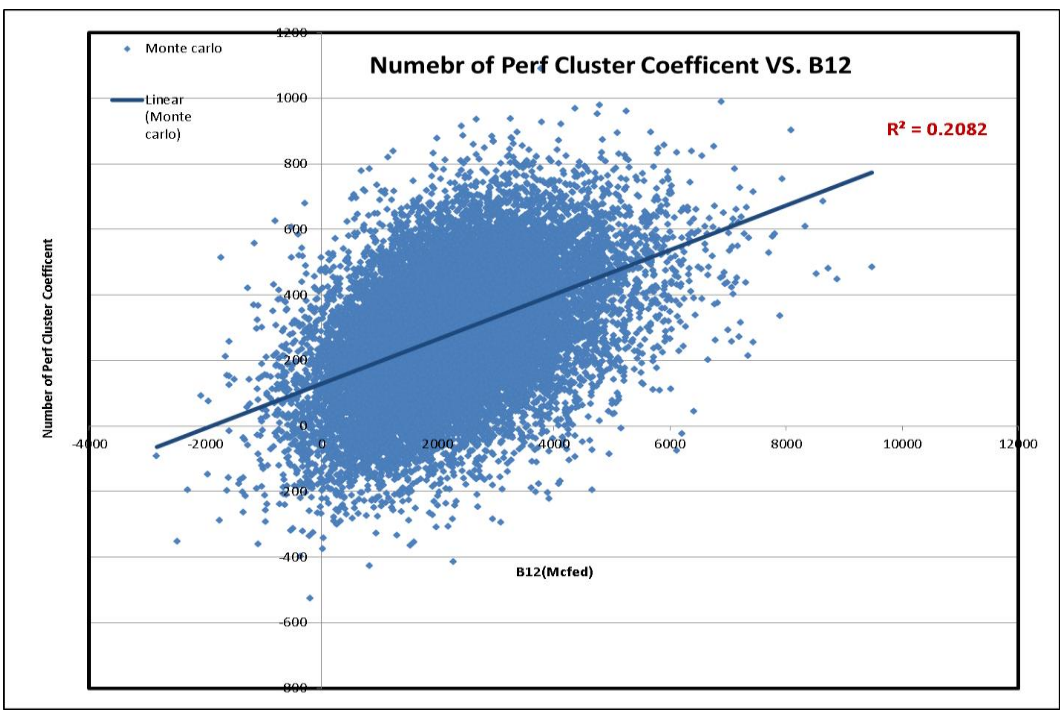


Fig. 80- # perforation cluster vs. B12- LL per stage, FS, PC per stage, fluid per stage, intercept = 0

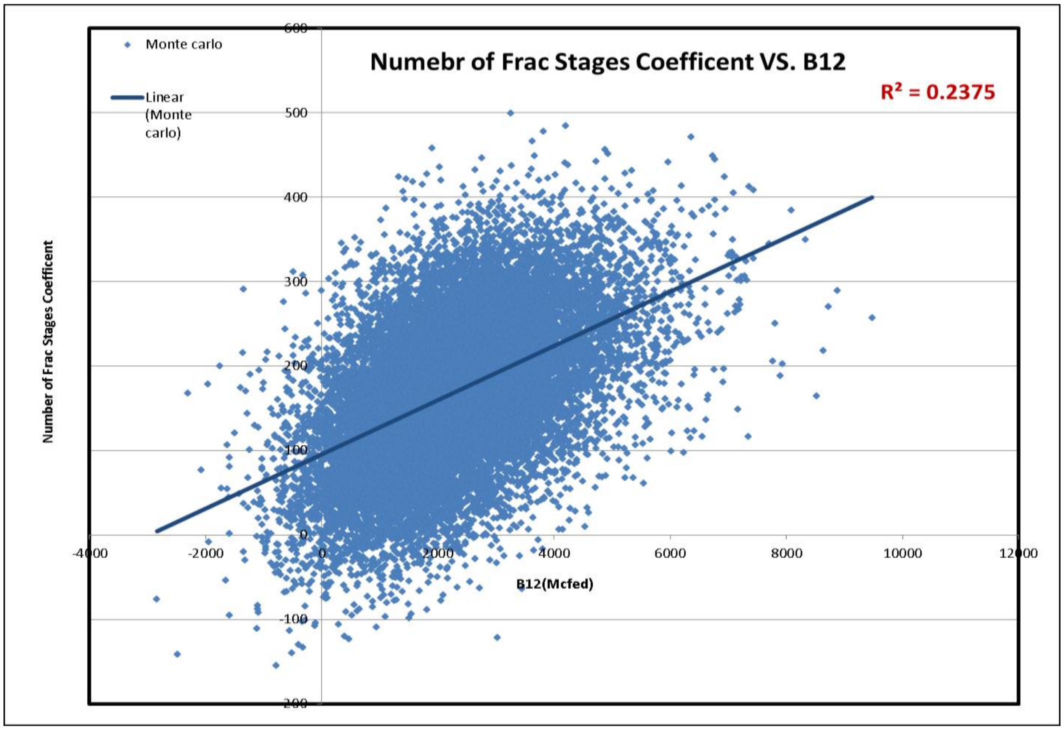


Fig. 81- #Fracture stages vs. B12- LL per stage, FS, PC per stage, fluid per stage, intercept = 0

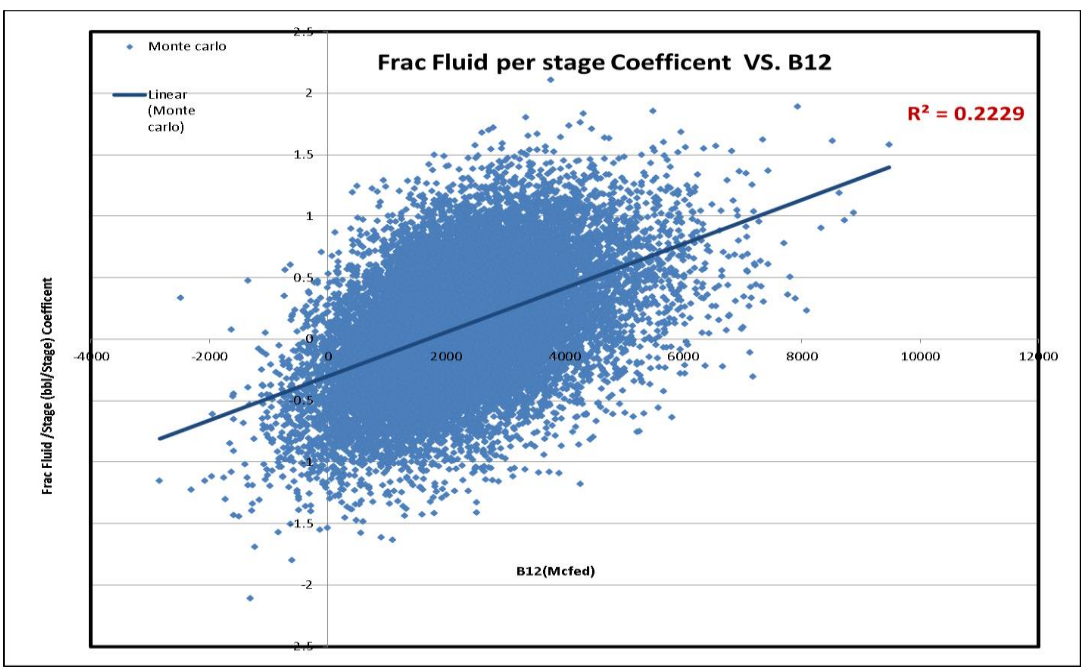


Fig. 82- Fracture fluid per stage vs. B12- LL per stage, FS, PC per stage, fluid per stage- intercept = 0

Model (127 Data Points)	F	Significance F	Adjusted R2	Number of Iteration	% Negative B12	Least important coeffceint	P-value of Least important coeffceint
LL , FS, PC per Stage, Fluid , Intercept :0	141.36	8.04814E-45	0.81	13000	3.20%	Lateral Length	0.95
LL , FS, PC per Stage, Fluid , Intercept	4.85	0.001149629	0.11	19220	3.50%	Lateral Length	0.54
LL per Stage, FS, PC per Stage, Fluid per Stage , Intercept :0	139.64	1.48466E-44	0.81	19220	1.9%	Lateral Length per Stage	0.93
LL per Stage, FS, PC per Stage, Fluid per Stage , Intercept	4.98	0.000945625	0.11	19200	3.40%	Frac Fluid per Stage	0.97

Fig. 83- Four models summary

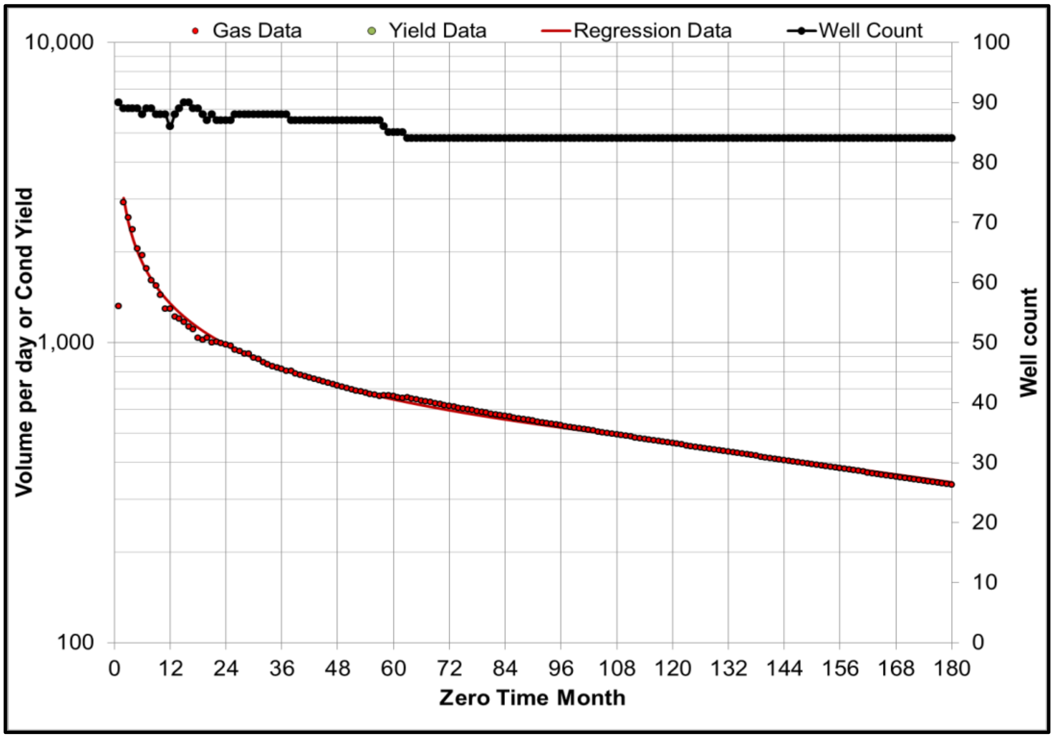


Fig. 84- Type curve-all wells-Altares

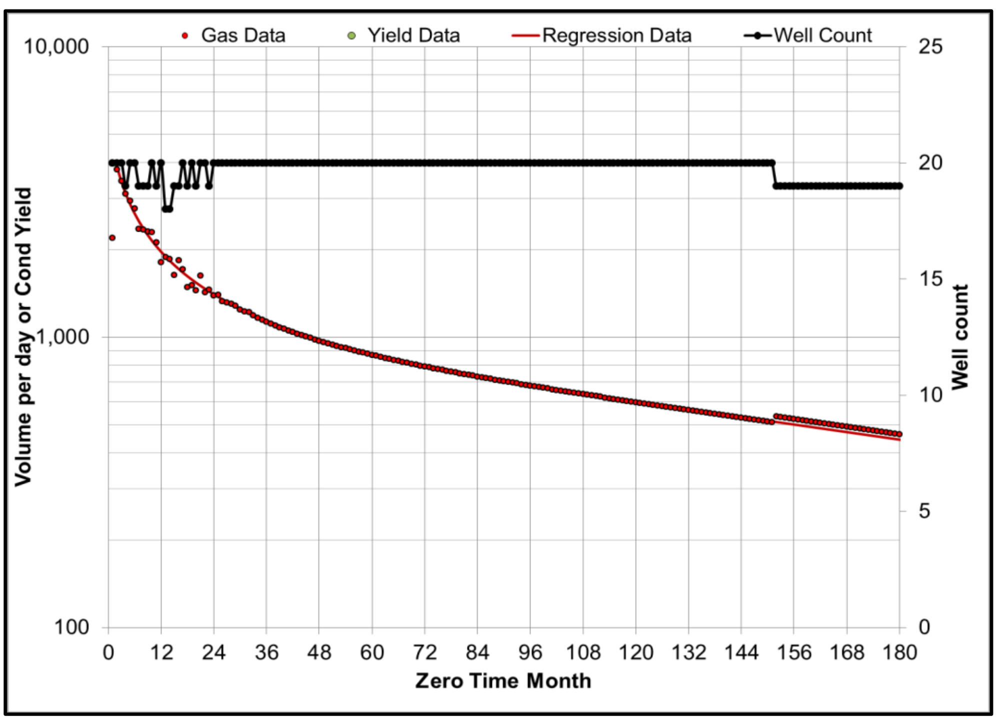


Fig. 85- Type curve- all wells-Blair

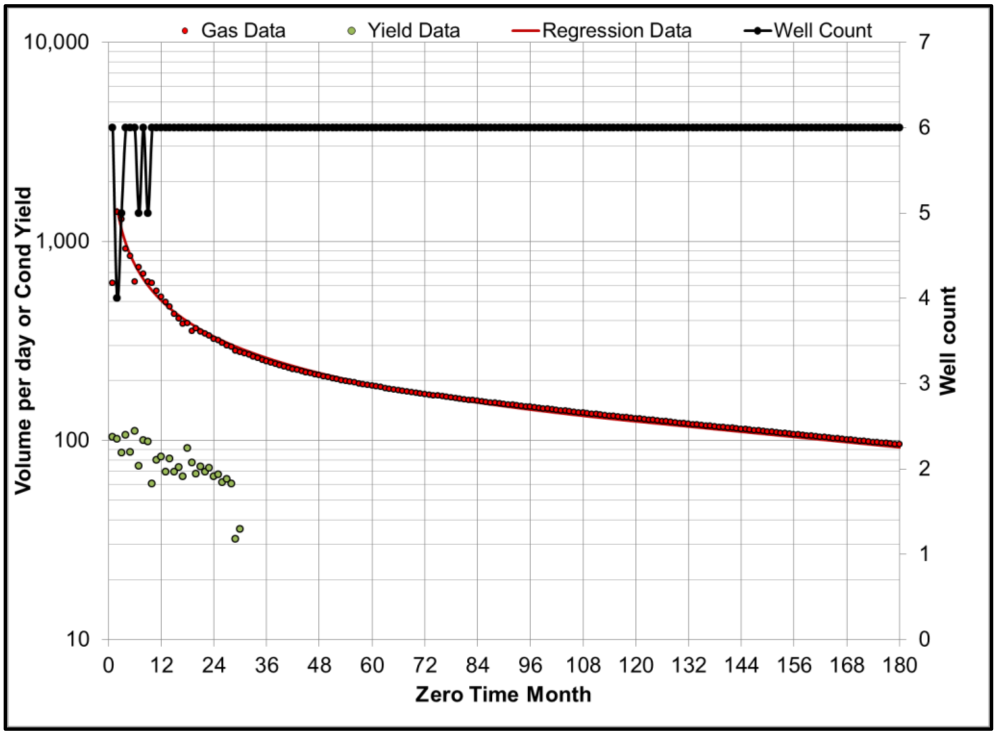


Fig. 86- Type curve- all wells-Blueberry

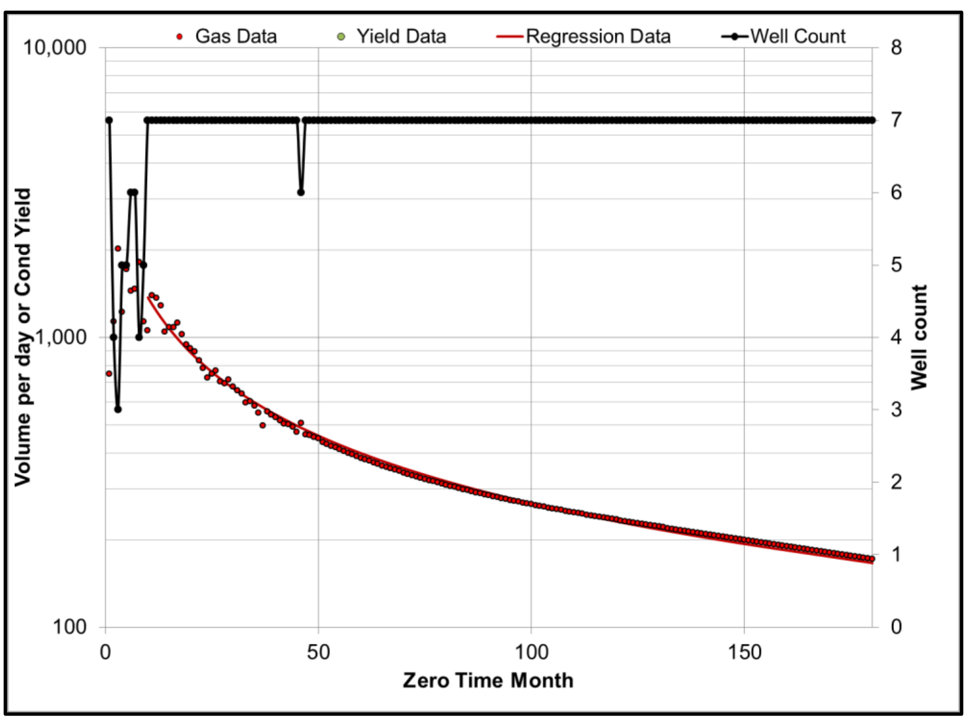


Fig. 87- Type curve- all wells-Brassey

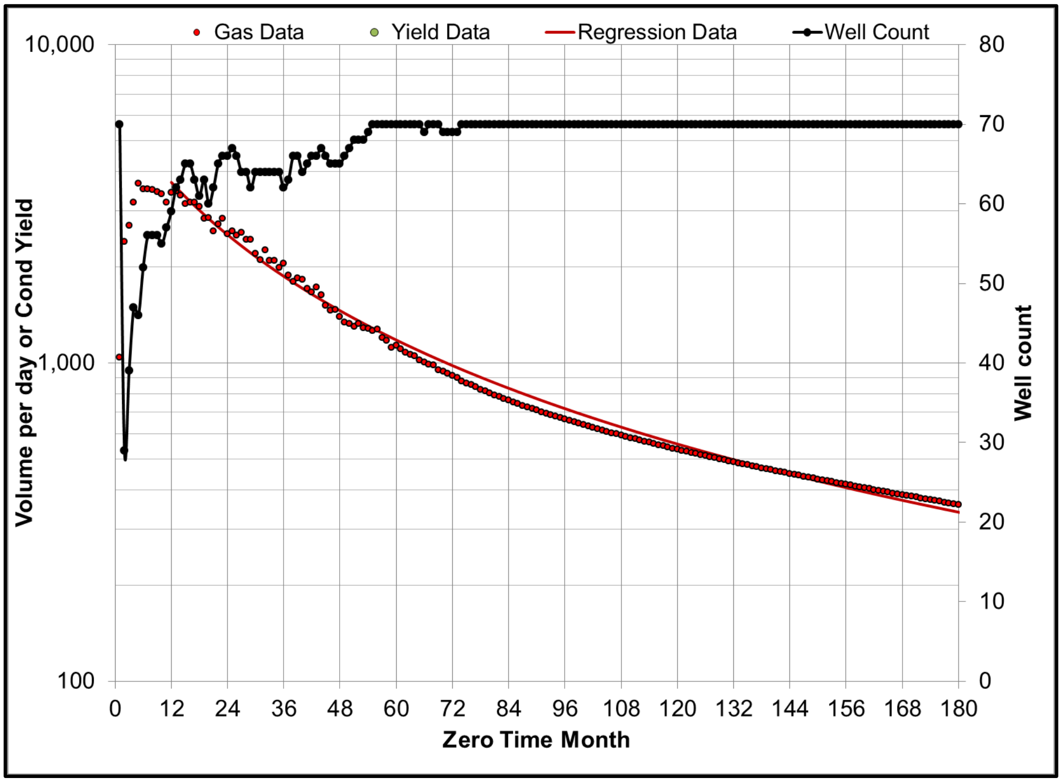


Fig. 88- Type curve- all wells-Dawson

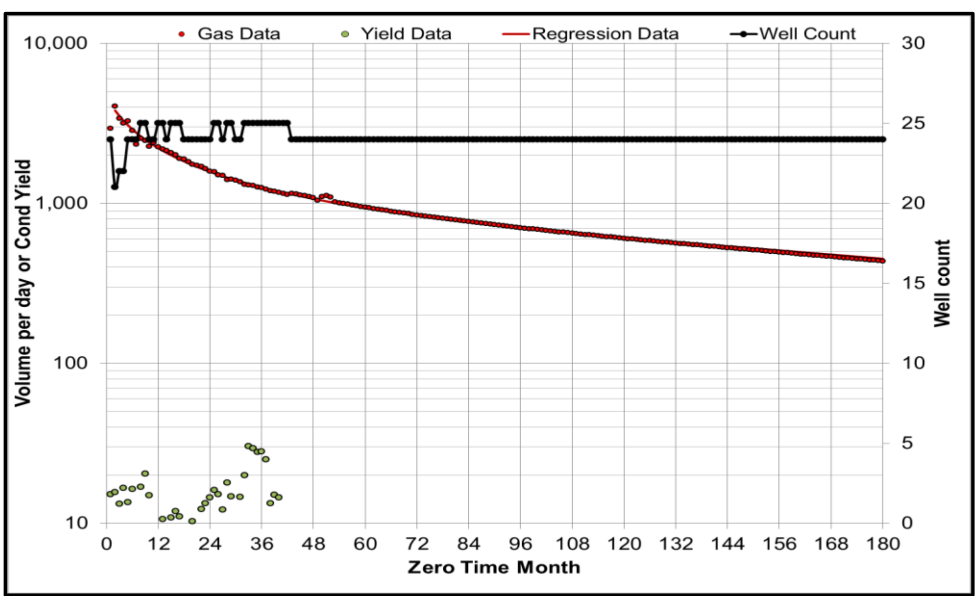


Fig. 89- Type curve- all wells-Graham

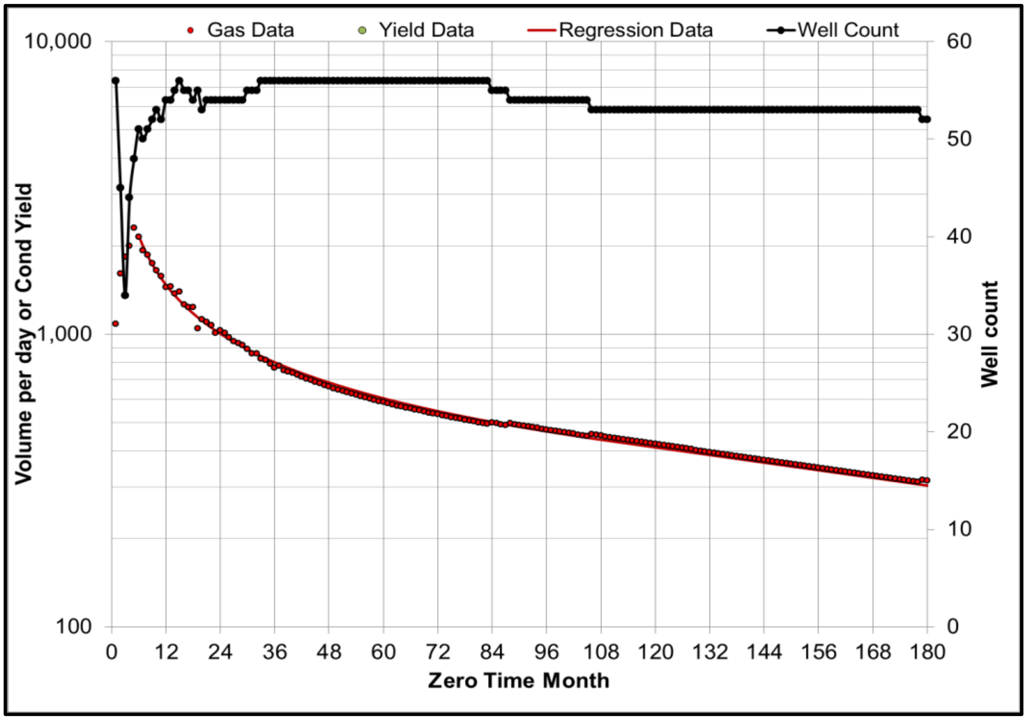


Fig. 90- Type curve- all wells-Ground birch north

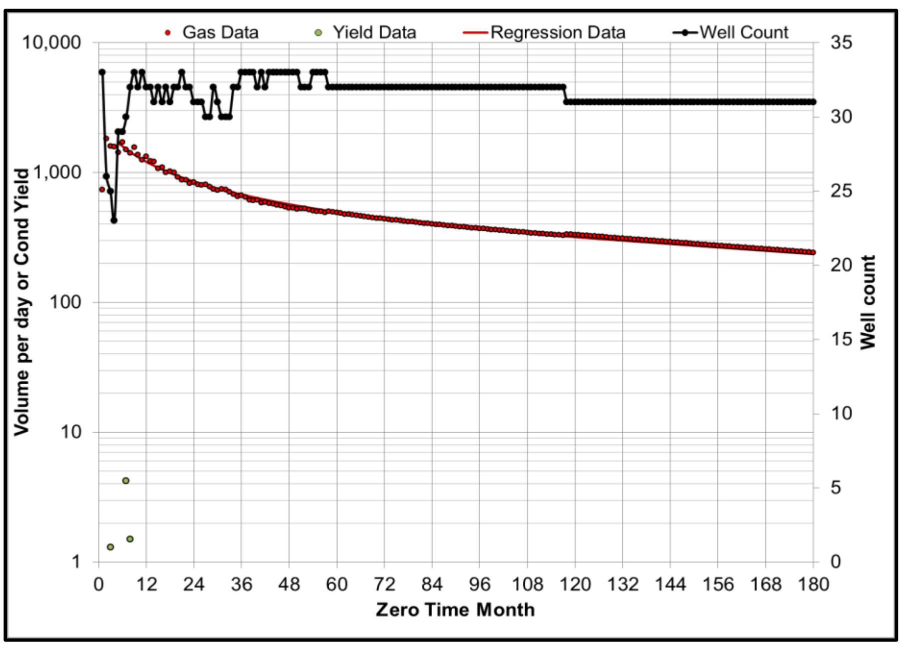


Fig. 91- Type curve- all wells-Ground birch south

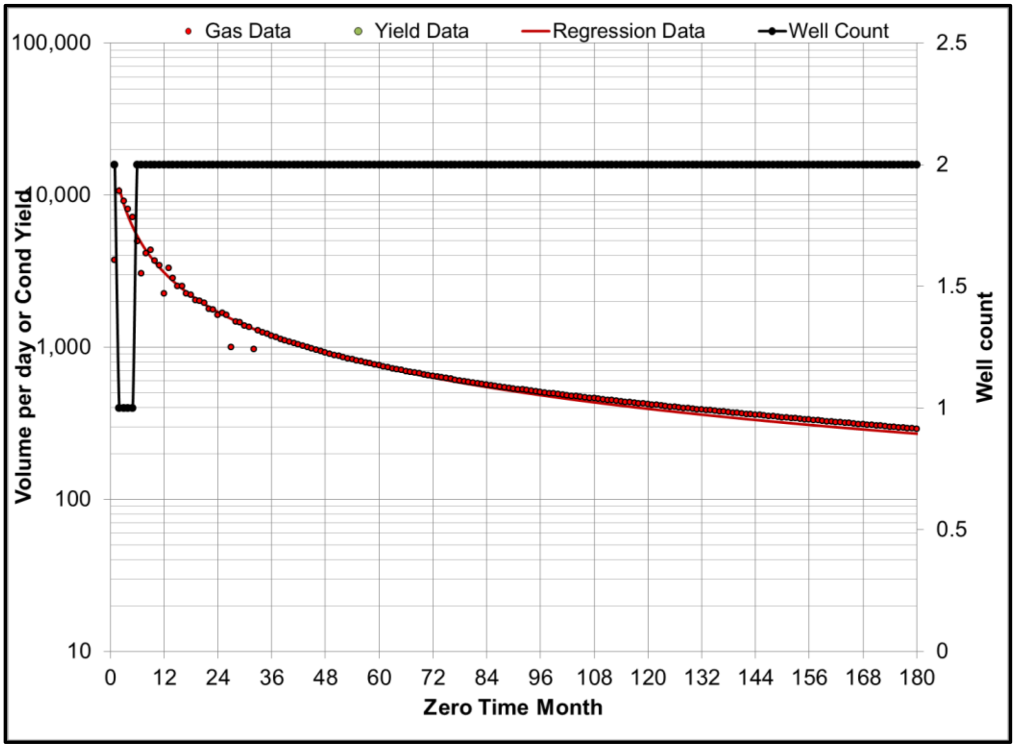


Fig. 92- Type curve- all wells-Gundy

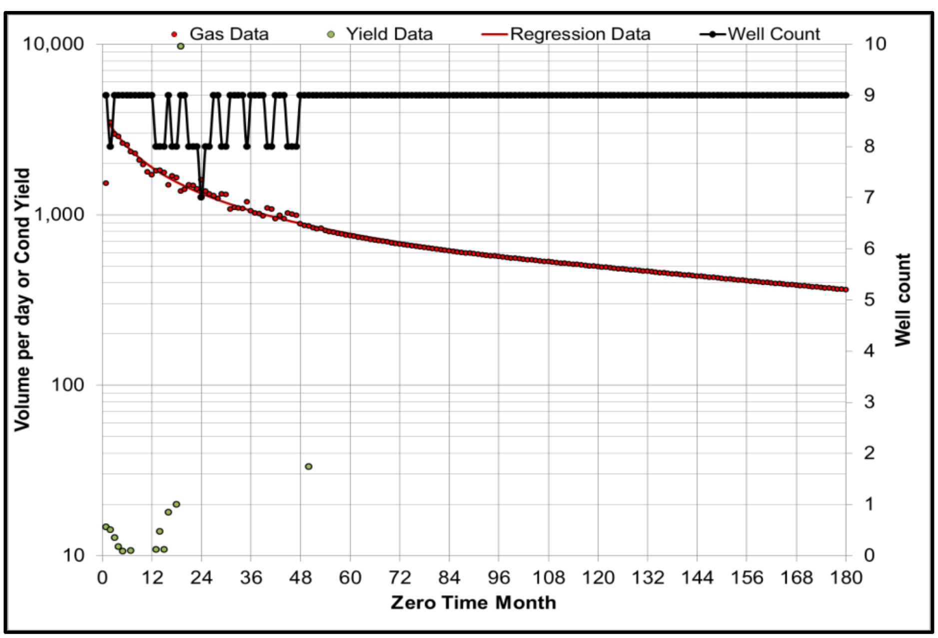


Fig. 93- Type curve- all wells-Kobes

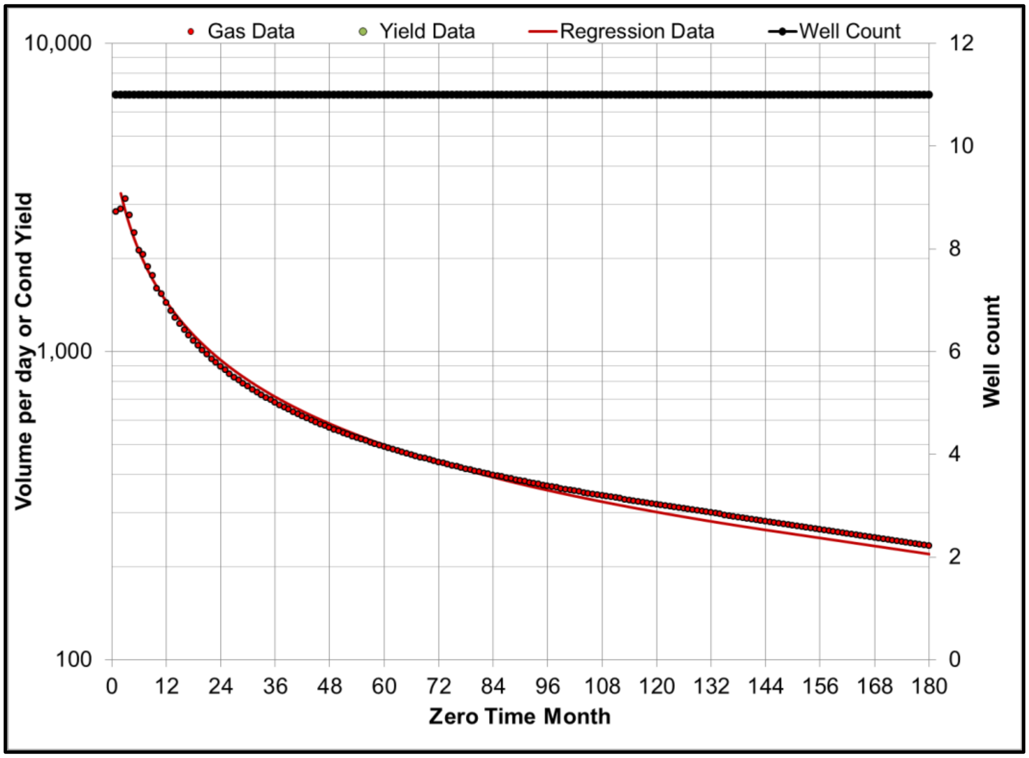


Fig. 94- Type curve- all wells-Lily

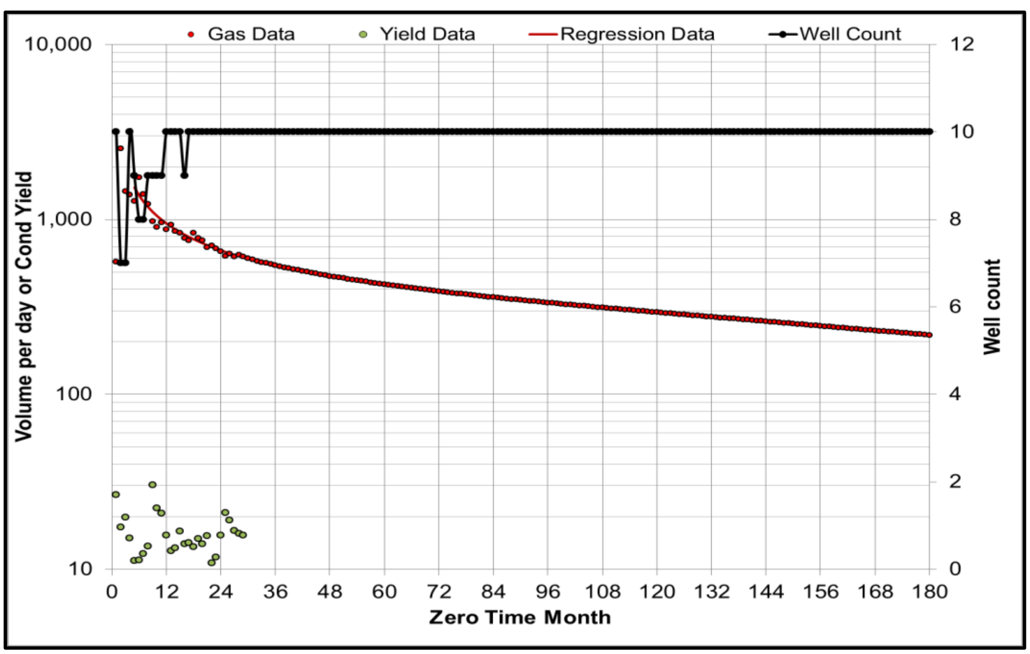


Fig. 95- Type curve- all wells-Nig

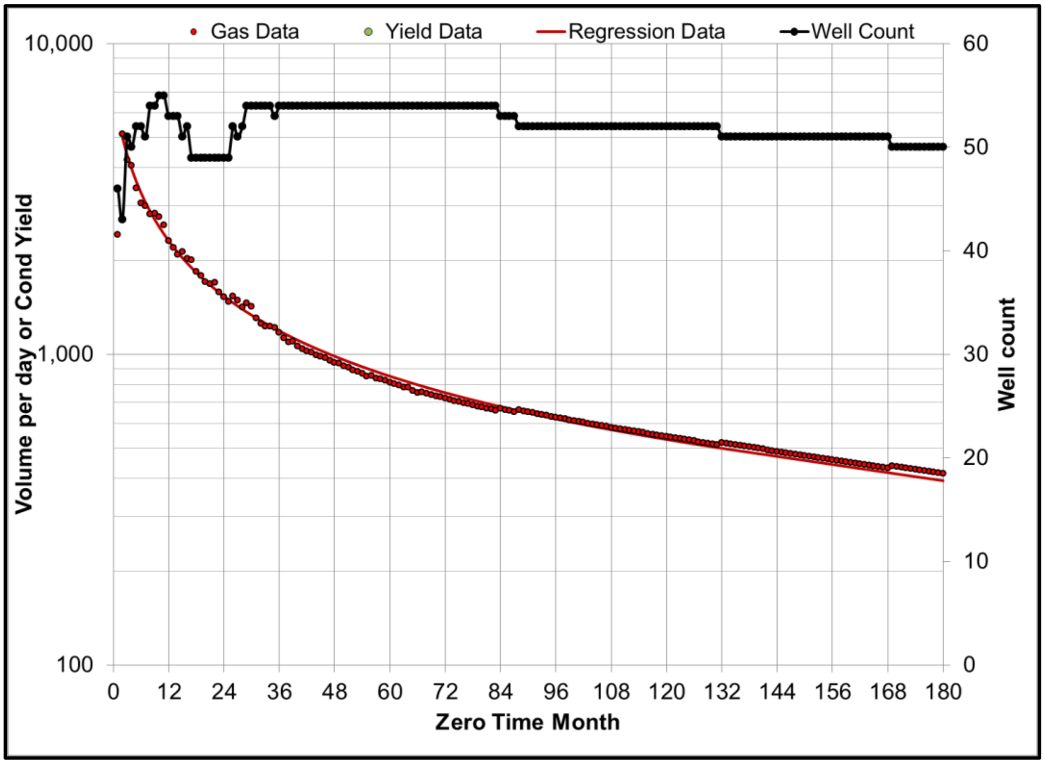


Fig. 96- Type curve- all wells-Parkland

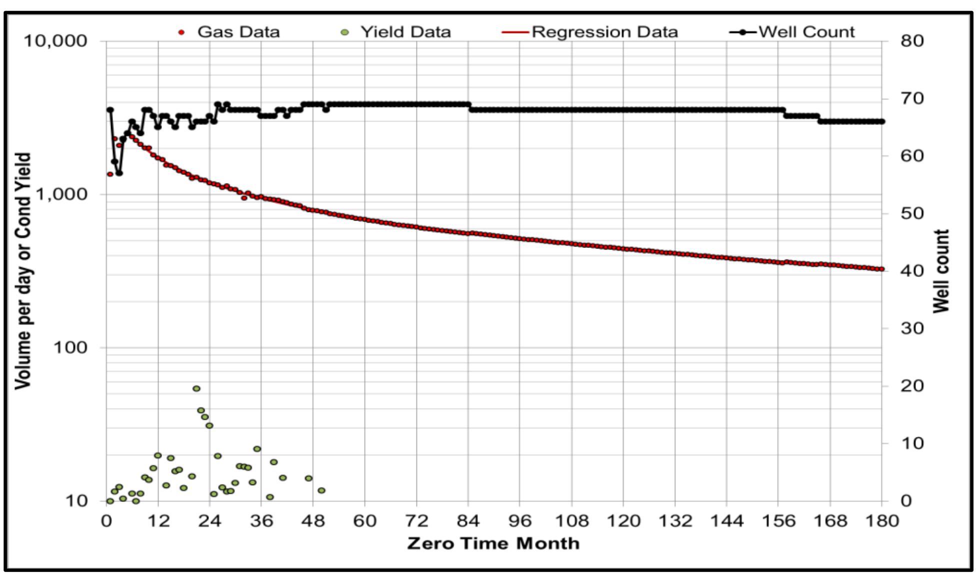


Fig. 97- Type curve- all wells-Septimus

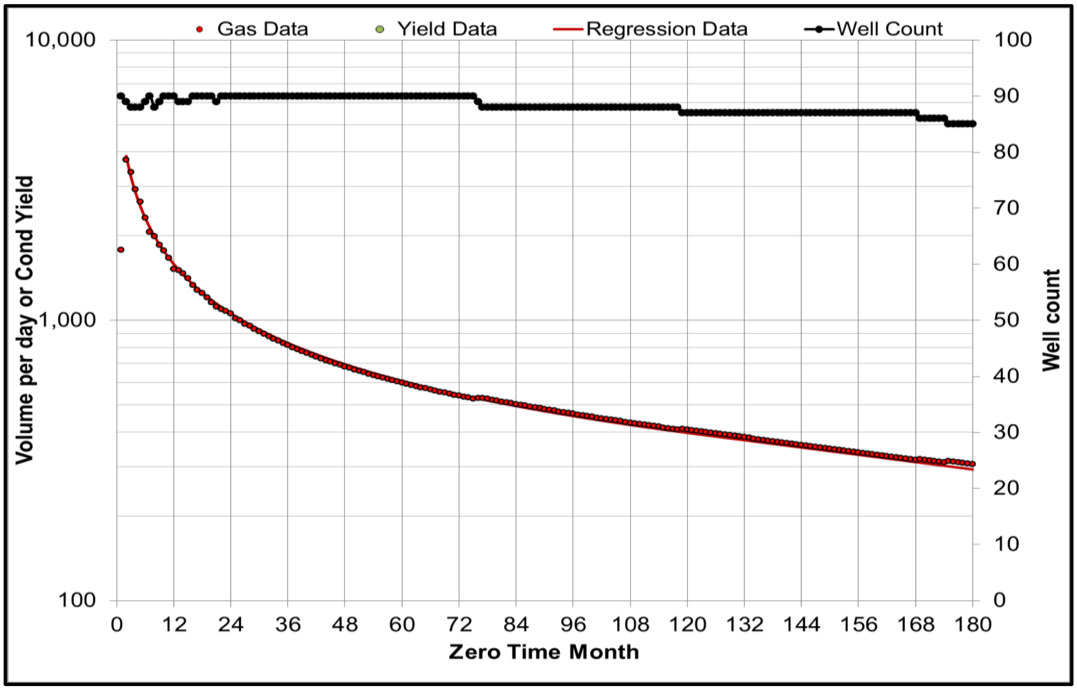


Fig. 98- Type curve- all wells-Sundown

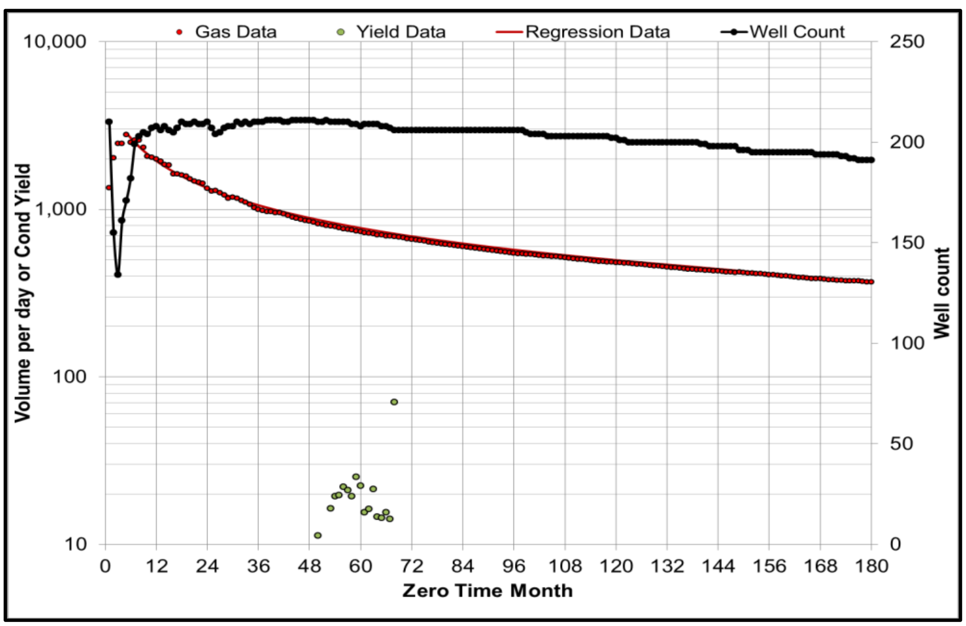


Fig. 99- Type curve- all wells-Sunset-Sunrise

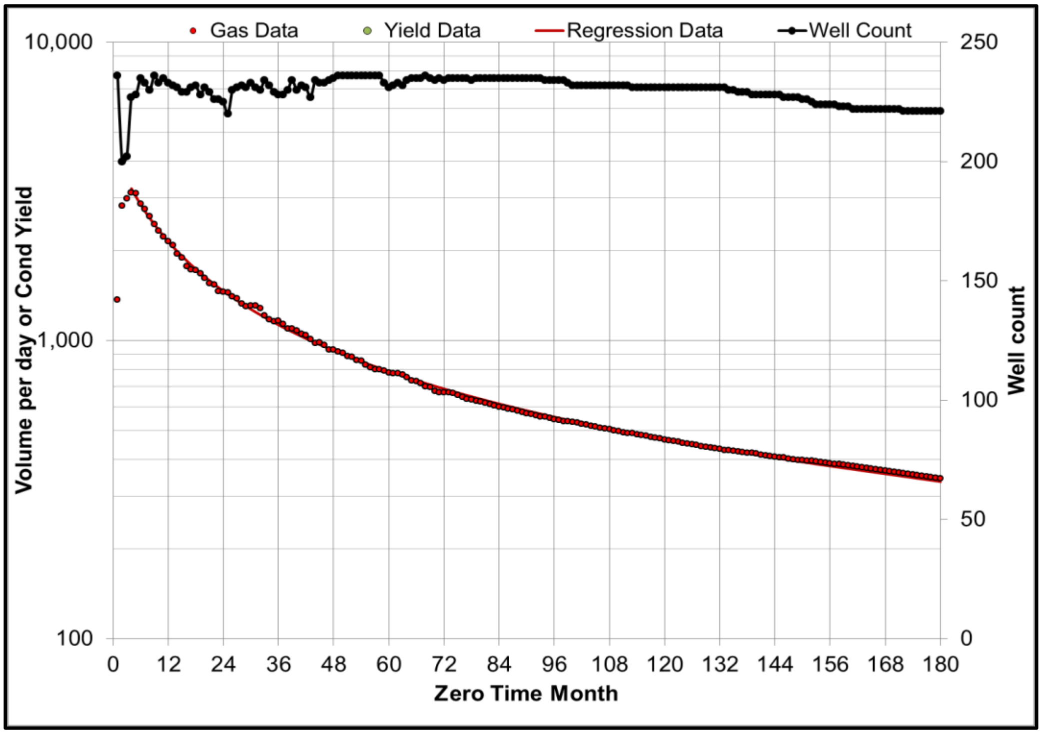


Fig. 100- Type curve- all wells-Swan

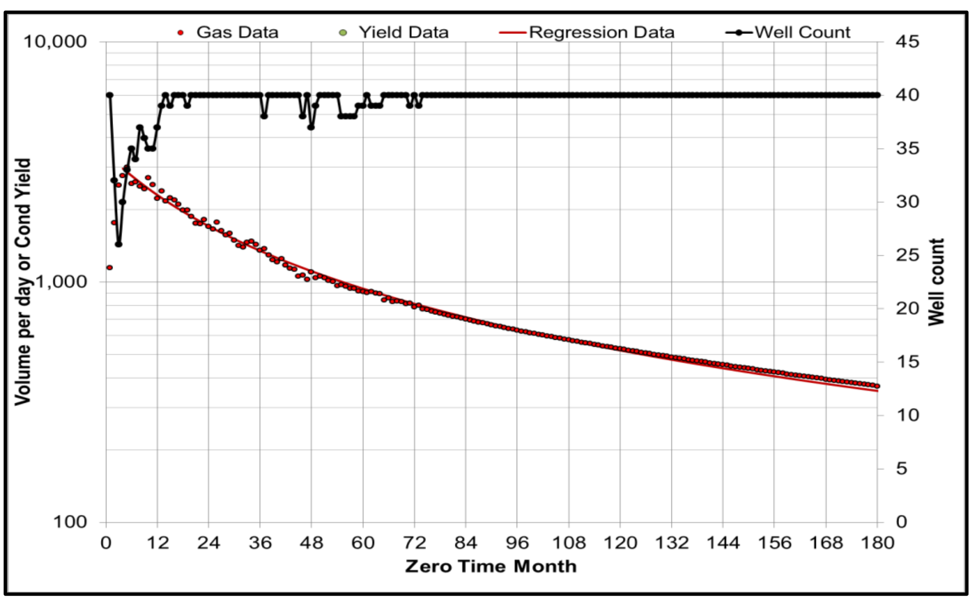


Fig. 101- Type curve- all wells-Swan North

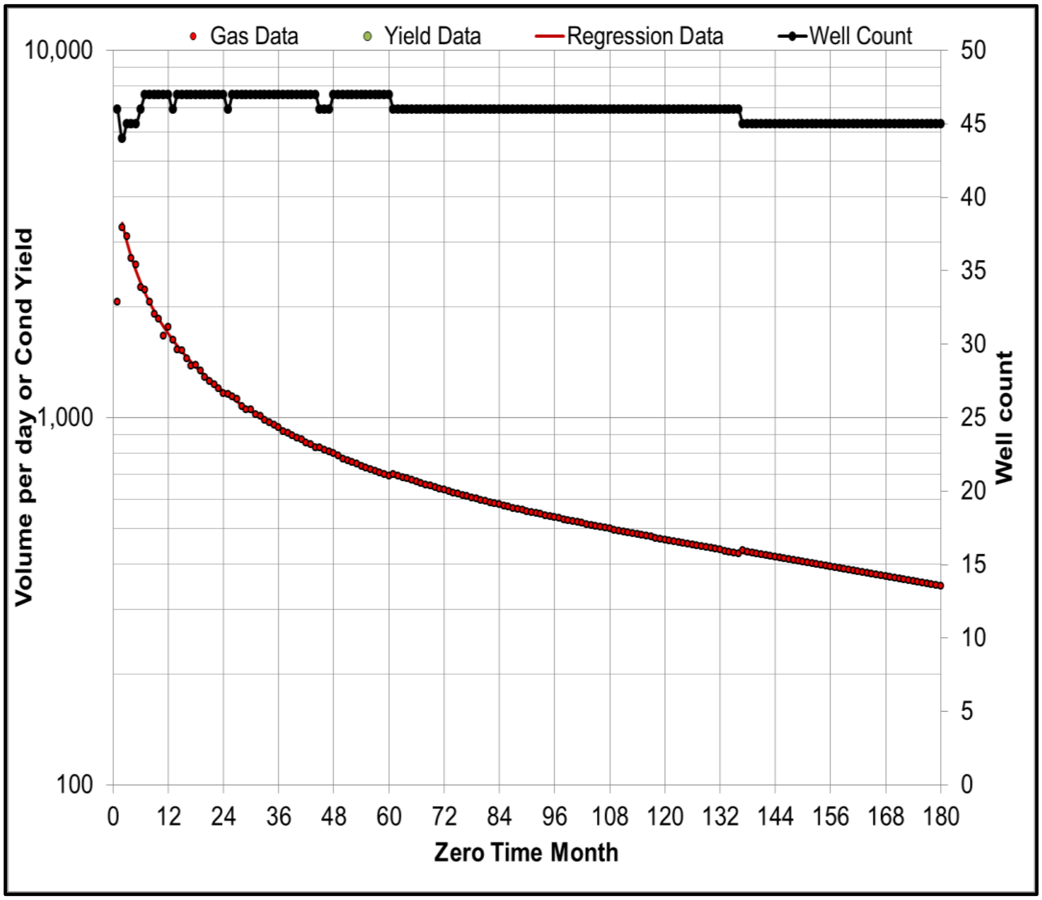


Fig. 102- Type curve- all wells-Town

Table 40- B12 vs. lateral length

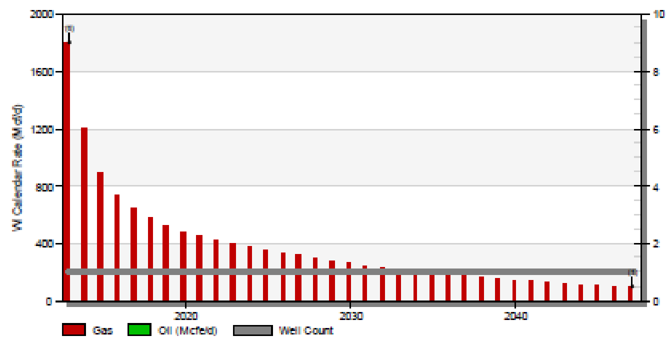
Field	# wells	type of equation	form of equation	Correlation(R2)	Pattern
Altares	23	Power	$y = 123.44x^{0.4593}$	0.05	Yes
Blair	4	Exponential	$y = 11901e^{-0.001x}$	0.41	Yes
Blueberry	1	–	–	–	–
Brassey	7	Linear	$y = -1.1783x + 2578.4$	0.16	Yes
Caribou	3	Linear	$y = -10.024x + 15999$	1.00	Yes
Chowade	0	–	–	–	–
Cypress	1	–	–	–	–
Daiber	2	Linear	$y = 18.271x - 15650$	1.00	Yes
Dawson	29	Linear	$y = 1.1426x + 3187.4$	0.05	Yes
Doe	2	Linear	$y = 13.349x - 16612$	1.00	Yes
Graham	4	Linear	$y = -1.8397x + 7890.6$	0.01	Yes
Groundbirch	15	Power	$y = 0.0001x^{2.2638}$	0.42	Yes
Gundy	8	Linear	$y = 3.5363x - 865.31$	0.14	Yes
Kobes	5	Linear	$y = -8.5788x + 16280$	0.86	Yes
Monias	4	Linear	$y = 8.5174x - 5715.2$	0.25	Yes
Parkland	15	Power	$y = 147.92x^{0.4812}$	0.08	Yes
Saturn	6	Linear	$y = -4.0092x + 10274$	0.17	Yes
Septimus	15	Exponential	$y = 1116e^{0.0007x}$	0.06	Yes
Sundown	5	Linear	$y = -3.3881x + 6817.5$	0.47	Yes
Sunset	28	Exponential	$y = 2446.9e^{0.0003x}$	0.10	Yes
Sunrise	30	Linear	$y = 0.8708x + 1810.1$	0.03	Yes
Swan	166	Linear	$y = -0.2579x + 4194.4$	0.002	No
Town	45	Power	$y = 17.943x^{0.7354}$	0.05	Yes
Tupper	1	–	–	–	–
W Gundy	4	Power	$y = 1E+30x^{-8.354}$	0.73	Yes
Wilder	2	Linear	$y = 5.4155x - 4724.1$	1.00	Yes

Groundbirch North

Price Deck: Fixed 5 Gas
Montney Area Completion Study
Results as of July 01, 2013

Evaluation Parameters

Reserves Category	Proved Developed Producing
Plan	Working
Reference Date	July 01, 2013
Discount Date	July 01, 2013
Econ. Calc. Date	July 01, 2013
Country	Canada
Province	British Columbia
Company Share	100.00 %
Price Deck	Fixed 5 Gas
Price Set	Base Price Set
Economic Limit	Applied - BTCF 0.00 %
Scenario	Fixed 5 Gas
GCA Applied	No
BOE Ratio	6:1 Mcf/bbl
Chance of Success	100.0 %
Chance of Occurrence	100.0 %
Oil Reserves Type	N/A
Gas Reserves Type	Gas



Remaining Reserves / Net Revenue NPV (M$C) / Price

		Gross	WI	RI	Net		0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %	Average
Oil	Mbbl	-	-	-	-	Oil	-	-	-	-	-	-	-
Gas	MMcf	4,374.6	4,374.6	-	3,513.0	Gas	19,440.9	12,767.8	10,682.7	9,687.3	7,985.7	6,914.3	5.29
Liquids	Mbbl	37.2	37.2	-	29.7	Liquids	1,943.0	1,305.4	1,101.4	1,002.8	831.8	722.3	63.39
NGL	Mbbl	-	-	-	-	NGL	-	-	-	-	-	-	-
Condensate	Mbbl	-	-	-	-	Condensate	-	-	-	-	-	-	-
C2	Mbbl	-	-	-	-	C2	-	-	-	-	-	-	-
C3	Mbbl	13.7	13.7	-	11.0	C3	282.8	190.0	160.3	146.0	121.1	105.1	25.00
C4	Mbbl	13.3	13.3	-	10.6	C4	821.0	551.6	465.4	423.7	351.5	305.2	75.00
C5+	Mbbl	10.2	10.2	-	8.1	C5+	839.2	563.8	475.7	433.1	359.3	312.0	100.00
Sulphur	MLT	-	-	-	-	Sulphur	-	-	-	-	-	-	-
Total	**MBOE**	**788.3**	**788.3**	**-**	**616.2**	**Total**	**21,383.8**	**14,073.2**	**11,784.1**	**10,890.1**	**8,817.6**	**7,636.8**	**33.30**

Cash Flow NPV (M$C)

BT Cash Flow	8,798.4	4,592.2	3,134.9	2,406.2	1,103.9	245.5

Risked Capital Costs (M$C)

	Gross	Co. Share
Land (COGPE)	-	-
Exploration (CEE)	-	-
Development (CDE)	6,122.0	6,122.0
Other Capital (CCA)	-	-
Total	**6,122.0**	**6,122.0**

Cash Flow (M$C)

	Co. Share	% of Sales Rev.
Revenue	25,516.9	
Royalties/Burdens	4,133.1	16.2
Operating Cost	6,463.5	25.3
Abandonment/Salvage	-	-
Oth. Rev./Oth. Deduct.	-	-
Capital	6,122.0	24.0
(Credit)/Surcharge	-	-
BT Cash Flow	**8,798.4**	**34.5**

Economic Indicators

	Before Tax
Rate of Return (%)	21.8
Payout (yrs from Jul 2013)	3.9
Payout (date)	Jun 2017
P/I - 0.0 % Discount	1.44
P/I - 10.0 % Discount	0.39
Init. Value (M$C/(BOE/d))	23.42

	WI	Co. Share	Net
Op. Cost ($C/BOE)	8.44	8.44	10.51
Cap. Cost ($C/BOE)	7.99	7.99	9.95

Annual Co. Share Cash Flow

Year	Well Count	Rate Mcfe/d	Avg. Price $C/Mcfe	WI Revenue M$C	Royalty Revenue M$C	Roy. / Burden M$C	Operating Cost M$C	Abandon. / Salvage M$C	Other Revenue M$C	Other Deductions M$C	Credit / (Surcharge) M$C	Net Op. Income M$C	Capital Cost M$C	BTax Cash Flow M$C
2013 (6)	1.00	1,890.0	5.55	1,930.1	-	57.9	207.1	-	-	-	-	1,665.1	6,122.0	-4,456.9
2014	1.00	1,264.2	5.55	2,561.0	-	225.7	305.6	-	-	-	-	2,029.7	-	2,029.7
2015	1.00	935.7	5.55	1,895.5	-	499.0	251.8	-	-	-	-	1,144.7	-	1,144.7
2016	1.00	771.9	5.55	1,567.9	-	402.6	226.8	-	-	-	-	938.5	-	938.5
2017	1.00	669.5	5.55	1,356.3	-	332.4	211.5	-	-	-	-	812.4	-	812.4
2018	1.00	598.0	5.55	1,211.5	-	282.6	201.9	-	-	-	-	727.1	-	727.1
2019	1.00	544.6	5.55	1,103.2	-	245.4	195.4	-	-	-	-	662.4	-	662.4
2020	1.00	502.6	5.55	1,020.9	-	217.3	191.1	-	-	-	-	612.6	-	612.6
2021	1.00	468.6	5.55	949.3	-	193.9	187.6	-	-	-	-	567.7	-	567.7
2022	1.00	440.2	5.55	891.8	-	175.3	185.4	-	-	-	-	531.0	-	531.0
Rem.	1.00	225.9	5.55	11,029.4	-	1,501.0	4,299.3	-	-	-	-	5,229.1	-	5,229.1
33.58 yr		374.8	5.55	25,516.9	-	4,133.1	6,463.5	-	-	-	-	14,920.4	6,122.0	8,798.4

* Tax pro-rated to start at 7/1/2013

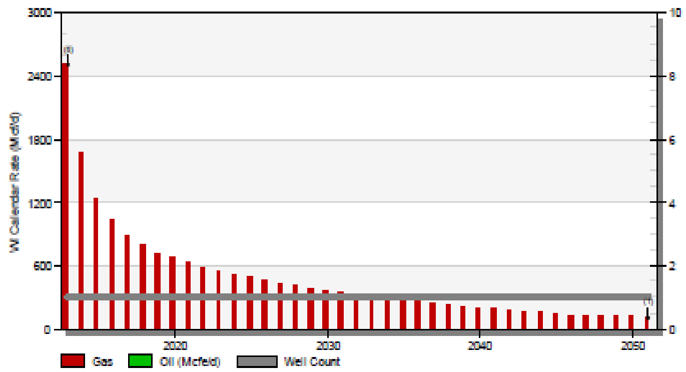
Fig. 103- Example of summary report -before tax –Groundbirch North- before adjustments

Groundbirch North

Price Deck: Fixed 5 Gas
Montney Area Completion Study
Results as of July 01, 2013

Evaluation Parameters

Reserves Category	Proved Developed Producing
Plan	Working
Reference Date	July 01, 2013
Discount Date	July 01, 2013
Econ. Calc. Date	July 01, 2013
Country	Canada
Province	British Columbia
Company Share	100.00 %
Price Deck	Fixed 5 Gas
Price Set	Base Price Set
Economic Limit	Applied - BTCF 0.00 %
Scenario	Fixed 5 Gas
GCA Applied	No
BOE Ratio	6:1 Mcf/bbl
Chance of Success	100.0 %
Chance of Occurrence	100.0 %
Oil Reserves Type	N/A
Gas Reserves Type	Gas



Remaining Reserves / Net Revenue NPV (M$C) / Price

		Gross	WI	RI	Net		0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %	Average
Oil	Mbbl	-	-	-	-	Oil	-	-	-	-	-	-	-
Gas	MMcf	6,241.4	6,241.4	-	4,881.8	Gas	26,688.7	17,109.5	14,245.5	12,898.3	10,618.4	9,192.7	5.29
Liquids	Mbbl	53.0	53.0	-	42.4	Liquids	2,746.4	1,801.7	1,511.1	1,372.3	1,134.0	982.4	63.39
NGL	Mbbl	-	-	-	-	NGL	-	-	-	-	-	-	-
Condensate	Mbbl	-	-	-	-	Condensate	-	-	-	-	-	-	-
C2	Mbbl	-	-	-	-	C2	-	-	-	-	-	-	-
C3	Mbbl	19.6	19.6	-	15.7	C3	399.7	262.2	219.9	199.7	165.0	143.0	25.00
C4	Mbbl	18.9	18.9	-	15.1	C4	1,160.4	761.3	638.5	579.9	479.2	415.1	75.00
C5+	Mbbl	14.5	14.5	-	11.6	C5+	1,186.2	778.2	652.7	592.7	489.8	424.3	100.00
Sulphur	MLT	-	-	-	-	Sulphur	-	-	-	-	-	-	-
Total	**MBOE**	**1,093.2**	**1,093.2**	-	**856.0**	**Total**	**29,435.1**	**18,911.2**	**15,756.6**	**14,270.6**	**11,752.4**	**10,175.2**	**33.30**

Cash Flow NPV (M$C)

	0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %
BT Cash Flow	15,601.1	9,250.8	7,139.4	6,100.3	4,268.4	3,075.7

Risked Capital Costs (M$C)

	Gross	Co. Share
Land (COGPE)	-	-
Exploration (CEE)	-	-
Development (CDE)	5,500.0	5,500.0
Other Capital (OCA)	-	-
Total	**5,500.0**	**5,500.0**

Cash Flow (M$C)

	Co. Share	% of Sales Rev.
Revenue	36,405.3	
Royalties/Burdens	6,970.3	19.1
Operating Cost	8,333.9	22.9
Abandonment/Salvage	-	-
Oth. Rev./Oth. Deduct.	-	-
Capital	5,500.0	15.1
(Credit)/Surcharge	-	-
BT Cash Flow	**15,601.1**	**42.8**

Economic Indicators

	Before Tax
Rate of Return (%)	52.6
Payout (yrs from Jul 2013)	1.9
Payout (date)	Jun 2015
P/I - 0.0 % Discount	2.84
P/I - 10.0 % Discount	1.11
Init. Value (M$C/(BOE/d))	29.94

	WI	Co. Share	Net
Op. Cost ($C/BOE)	7.62	7.62	9.74
Cap. Cost ($C/BOE)	5.03	5.03	6.42

Annual Co. Share Cash Flow

Year	Well Count	Rate Mcfe/d	Avg. Price $C/Mcfe	WI Revenue M$C	Royalty Revenue M$C	Roy. / Burden M$C	Operating Cost M$C	Abandon. / Salvage M$C	Other Revenue M$C	Other Deductions M$C	Credit / (Surcharge) M$C	Net Op. Income M$C	Capital Cost M$C	BTax Cash Flow M$C
2013 (6)	1.00	2,622.0	5.55	2,677.6	-	80.3	272.1	-	-	-	-	2,325.1	5,500.0	-3,174.9
2014	1.00	1,753.8	5.55	3,552.8	-	661.6	393.1	-	-	-	-	2,498.0	-	2,498.0
2015	1.00	1,298.0	5.55	2,629.6	-	693.0	317.9	-	-	-	-	1,618.6	-	1,618.6
2016	1.00	1,070.8	5.55	2,175.1	-	573.2	282.6	-	-	-	-	1,319.3	-	1,319.3
2017	1.00	928.8	5.55	1,881.5	-	495.6	260.7	-	-	-	-	1,125.1	-	1,125.1
2018	1.00	829.6	5.55	1,680.7	-	438.5	246.7	-	-	-	-	995.4	-	995.4
2019	1.00	755.5	5.55	1,530.4	-	391.0	237.0	-	-	-	-	902.4	-	902.4
2020	1.00	697.2	5.55	1,416.3	-	352.5	230.4	-	-	-	-	833.4	-	833.4
2021	1.00	650.1	5.55	1,316.9	-	318.9	224.9	-	-	-	-	773.0	-	773.0
2022	1.00	610.7	5.55	1,237.1	-	291.4	221.2	-	-	-	-	724.5	-	724.5
Rem.	1.00	286.4	5.55	16,307.5	-	2,674.1	5,647.2	-	-	-	-	7,986.2	-	7,986.2
37.58 yr		477.8	5.55	36,405.3	-	6,970.3	8,333.9	-	-	-	-	21,101.1	5,500.0	15,601.1

* Tax pro-rated to start at 7/1/2013

Fig. 104- Example of summary report -before tax- Groundbirch North- after adjustment

Groundbirch North

Price Deck: Fixed 4 Gas
Montney Area Completion Study
Results as of July 01, 2013

		WI Share Oil				WI Share Sales Gas				WI Share Liquids				WI Share Sulphur				
Year	WI Wells	Cal Day Rate bbl/d	Volume Mbbl	Avg. Price $C/bbl	Sales Revenue M$C	Cal Day Rate Mcf/d	Volume MMcf	Avg. Price $C/Mcf	Sales Revenue M$C	Cal Day Rate bbl/d	Volume Mbbl	Avg. Price $C/bbl	Sales Revenue M$C	Cal Day Rate LT/d	Volume MLT	Avg. Price $C/LT	Sales Revenue M$C	WI Sales Revenue M$C
2013 (6)	1.00	-	-	-	-	2,494.8	459.0	4.24	1,944.3	21.2	3.9	63.39	247.2	-	-	-	-	2,191.5
2014	1.00	-	-	-	-	1,668.7	609.1	4.24	2,579.9	14.2	5.2	63.39	327.9	-	-	-	-	2,907.8
2015	1.00	-	-	-	-	1,235.1	450.8	4.24	1,909.5	10.5	3.8	63.39	242.7	-	-	-	-	2,152.2
2016	1.00	-	-	-	-	1,018.8	372.9	4.24	1,579.4	8.7	3.2	63.39	200.8	-	-	-	-	1,780.2
2017	1.00	-	-	-	-	883.7	322.6	4.24	1,366.2	7.5	2.7	63.39	173.7	-	-	-	-	1,539.9
2018	1.00	-	-	-	-	789.4	288.1	4.24	1,220.4	6.7	2.4	63.39	155.1	-	-	-	-	1,375.6
2019	1.00	-	-	-	-	718.8	262.4	4.24	1,111.3	6.1	2.2	63.39	141.3	-	-	-	-	1,252.6
2020	1.00	-	-	-	-	663.4	242.8	4.24	1,028.5	5.6	2.1	63.39	130.7	-	-	-	-	1,159.2
2021	1.00	-	-	-	-	618.5	225.8	4.24	956.2	5.3	1.9	63.39	121.6	-	-	-	-	1,077.8
2022	1.00	-	-	-	-	581.1	212.1	4.24	898.3	4.9	1.8	63.39	114.2	-	-	-	-	1,012.5
2023	1.00	-	-	-	-	547.2	199.7	4.24	846.0	4.6	1.7	63.39	107.5	-	-	-	-	953.6
2024	1.00	-	-	-	-	515.4	188.6	4.24	798.9	4.4	1.6	63.39	101.6	-	-	-	-	900.5
2025	1.00	-	-	-	-	485.3	177.1	4.24	750.3	4.1	1.5	63.39	95.4	-	-	-	-	845.7
2026	1.00	-	-	-	-	457.1	166.8	4.24	706.6	3.9	1.4	63.39	89.8	-	-	-	-	796.5
2027	1.00	-	-	-	-	430.5	157.1	4.24	665.5	3.7	1.3	63.39	84.6	-	-	-	-	750.1
Rem.	1.00	-	-	-	-	242.7	1,780.8	4.24	7,542.6	2.1	15.1	63.39	958.8	-	-	-	-	8,501.4
34.58 yr			-	-	-		6,115.8	4.24	25,894.1		51.9	63.39	3,292.9		-	-	-	29,187.0

	Crown Royalties			Freehold Royalties				Indian Royalties			Overriding Royalties						
Year	Unadj. Royalty M$C	Royalty Deduction M$C	Royalty Payable M$C	Unadj. Royalty M$C	Royalty Deduction M$C	Royalty Payable M$C	Mineral Tax M$C	Unadj. Royalty M$C	Royalty Deduction M$C	Royalty Payable M$C	Unadj. Royalty M$C	Royalty Deduction M$C	Royalty Payable M$C	NPI Payable M$C	Other Burdens M$C	Total Roy. & Burden M$C	Total Roy. & Burden %
2013 (6)	574.4	508.7	65.7	-	-	-	-	-	-	-	-	-	-	-	-	65.7	3.0
2014	762.1	391.3	370.8	-	-	-	-	-	-	-	-	-	-	-	-	370.8	12.8
2015	564.1	-	564.1	-	-	-	-	-	-	-	-	-	-	-	-	564.1	26.2
2016	466.6	-	466.6	-	-	-	-	-	-	-	-	-	-	-	-	466.6	26.2
2017	403.5	-	403.5	-	-	-	-	-	-	-	-	-	-	-	-	403.5	26.2
2018	357.0	-	357.0	-	-	-	-	-	-	-	-	-	-	-	-	357.0	26.0
2019	318.4	-	318.4	-	-	-	-	-	-	-	-	-	-	-	-	318.4	25.4
2020	287.3	-	287.3	-	-	-	-	-	-	-	-	-	-	-	-	287.3	24.8
2021	260.0	-	260.0	-	-	-	-	-	-	-	-	-	-	-	-	260.0	24.1
2022	237.7	-	237.7	-	-	-	-	-	-	-	-	-	-	-	-	237.7	23.5
2023	217.6	-	217.6	-	-	-	-	-	-	-	-	-	-	-	-	217.6	22.8
2024	199.3	-	199.3	-	-	-	-	-	-	-	-	-	-	-	-	199.3	22.1
2025	181.2	-	181.2	-	-	-	-	-	-	-	-	-	-	-	-	181.2	21.4
2026	165.0	-	165.0	-	-	-	-	-	-	-	-	-	-	-	-	165.0	20.7
2027	150.0	-	150.0	-	-	-	-	-	-	-	-	-	-	-	-	150.0	20.0
Rem.	1,237.8	-	1,237.8	-	-	-	-	-	-	-	-	-	-	-	-	1,237.8	14.6
34.58 yr	6,382.0	900.0	5,482.0	-	-	-	-	-	-	-	-	-	-	-	-	5,482.0	18.8

											Capital Costs					Before Tax Cash Flow		
Year	WI Sales Revenue M$C	Royalty Revenue M$C	Co. Share Revenue M$C	Total Roy. & Burden M$C	Net Revenue M$C	Operating Costs M$C	Abandon. & Salvage M$C	Other Revenue M$C	Sask Cap Surch M$C	Net Op. Income M$C	COGPE M$C	CEE M$C	CDE M$C	CCA M$C	Total M$C	BTCF M$C	Cum. M$C	NPV @ 10.00 % M$C
2013 (6)	2,191.5	-	2,191.5	65.7	2,125.8	272.1	-	-	-	1,853.6	-	-	5,500.0	-	5,500.0	-3,646.4	-3,646.4	-3,665.0
2014	2,907.8	-	2,907.8	370.8	2,537.0	393.1	-	-	-	2,143.8	-	-	-	-	-	2,143.8	-1,502.5	1,962.7
2015	2,152.2	-	2,152.2	564.1	1,588.1	317.9	-	-	-	1,270.2	-	-	-	-	-	1,270.2	-232.4	1,051.9
2016	1,780.2	-	1,780.2	466.6	1,313.6	282.6	-	-	-	1,031.0	-	-	-	-	-	1,031.0	798.7	775.9
2017	1,539.9	-	1,539.9	403.5	1,136.4	260.7	-	-	-	875.7	-	-	-	-	-	875.7	1,674.4	598.9
2018	1,375.6	-	1,375.6	357.0	1,018.5	246.7	-	-	-	771.8	-	-	-	-	-	771.8	2,446.2	479.7
2019	1,252.6	-	1,252.6	318.4	934.1	237.0	-	-	-	697.1	-	-	-	-	-	697.1	3,143.4	393.9
2020	1,159.2	-	1,159.2	287.3	871.9	230.4	-	-	-	641.5	-	-	-	-	-	641.5	3,784.9	329.5
2021	1,077.8	-	1,077.8	260.0	817.8	224.9	-	-	-	592.9	-	-	-	-	-	592.9	4,377.8	276.8
2022	1,012.5	-	1,012.5	237.7	774.8	221.2	-	-	-	553.7	-	-	-	-	-	553.7	4,931.4	235.0
2023	953.6	-	953.6	217.6	736.0	218.0	-	-	-	518.0	-	-	-	-	-	518.0	5,449.4	199.8
2024	900.5	-	900.5	199.3	701.2	215.4	-	-	-	485.8	-	-	-	-	-	485.8	5,935.3	170.4
2025	845.7	-	845.7	181.2	664.5	212.3	-	-	-	452.2	-	-	-	-	-	452.2	6,387.4	144.2
2026	796.5	-	796.5	165.0	631.5	209.8	-	-	-	421.7	-	-	-	-	-	421.7	6,809.1	122.2
2027	750.1	-	750.1	150.0	600.1	207.6	-	-	-	392.6	-	-	-	-	-	392.6	7,201.7	103.4
Rem.	8,501.4	-	8,501.4	1,237.8	7,263.6	3,976.8	-	-	-	3,286.7	-	-	-	-	-	3,286.7	10,488.4	497.4
34.58 yr	29,187.0	-	29,187.0	5,482.0	23,716.0	7,726.8	-	-	-	15,988.4	-	-	5,500.0	-	5,500.0	10,488.4		3,676.8

Country/Province	Canada/British Columbia
Mineral Owner	Crown
Prod. Category	Base 12 Gas
Incentive	Deep Gas Well
Econ. Calc. Date	Jul 2013
Avg. WI Share	100.00 %
Econ. Life/To Aban.	34.58 yr / 34.58 yr
Econ. RLI	5.63yr
Price Deck	Fixed 4 Gas
Price Set	Base Price Set
Economic Limit	Applied - BTCF 0.00 %
COS / COO	100.0 % / 100.0 %
Oil Reserves Type	N/A
Gas Reserves Type	Gas

	Remaining Reserves					Net Revenue NPV (M$C)					
Product	Gross	WI	RI	Co. Share	Net	0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %
Oil (Mbbl)	-	-	-	-	-	-	-	-	-	-	-
Sales Gas (MMcf)	6,115.8	6,115.8	-	6,115.8	4,764.5	21,008.3	13,749.2	11,508.9	10,443.7	8,627.0	7,483.9
Liquids (Mbbl)	51.9	51.9	-	51.9	41.6	2,706.7	1,806.2	1,521.1	1,383.8	1,146.4	994.6
Sulphur (MLT)	-	-	-	-	-	-	-	-	-	-	-
Total (MBOE) / Net Rev.	1,071.2	1,071.2	-	1,071.2	835.8	23,716.0	15,555.6	13,030.1	11,827.5	9,773.4	8,478.5
Total BTCF						10,488.4	5,899.5	4,450.6	3,676.8	2,293.4	1,379.8

Fig. 105- Example of economic detail report -before tax- Groundbirch North

APPENDIX B

Multivariate analysis –VBA code

In 2-D regression, we grouped the data by fracture fluid type and geographic area then plotted the EUR, B12 and B1 vs. completion parameters (LL, FS, PC, fluid, sand) for each group. For this purpose, we wrote the following code in VBA:

```
Option Explicit
Sub UpdateAnalysis()
Dim sFilter() As String
Dim sSheetName As String
Dim sDepVarRange As String
Dim sDepVarCol As String
Dim lRows As Long
Dim li As Long
Dim lj As Long
Dim lk As Long
Dim lFilters As Long

If VBA.UCase(Range("L2")) = "B1" Then
  sDepVarRange = "B3:B"
  sDepVarCol = "B"
ElseIf VBA.UCase(Range("L2")) = "B12" Then
  sDepVarRange = "C3:C"
  sDepVarCol = "C"
End If

lFilters = 0
For li = 2 To 51
  If VBA.Len(Range("M" & li)) > 0 Then
```

```
    lFilters = lFilters + 1
    ReDim Preserve sFilter(1 To lFilters)
    sFilter(lFilters) = VBA.UCase(Range("M" & li))
  End If
Next li
If lFilters = 0 Then
  ReDim sFilter(1 To 1)
  sFilter(1) = ""
  lFilters = 1
End If

Sheets("DATA_ANALYSIS").Select
Range("A4:K1000").ClearContents

Sheets("DATA").Select

Application.ScreenUpdating = False

lj = 0
For li = 4 To 1000
  For lk = 1 To lFilters
    If Not VBA.IsError(Range(sDepVarCol & li)) Then
      If VBA.UCase(Range("K" & li)) = sFilter(lk) Or (VBA.Len(sFilter(lk)) = 0 And Range("L" & li) = 2) Then
        Range("A" & li & ":K" & li).Select
        Selection.Copy
        Sheets("DATA_ANALYSIS").Select
        lj = lj + 1
        Range("A" & lj + 3).Select
        Selection.PasteSpecial Paste:=xlPasteValues, Operation:=xlNone, SkipBlanks _
            :=False, Transpose:=False
```

```
    Sheets("DATA").Select
   End If
  End If
 Next lk
Next li

Sheets("DATA_ANALYSIS").Select
lRows = lj + 3

sSheetName = "LL,FS,PC,FLUID DIVIDED BY PI"
DeleteSheet sSheetName
Application.Run "ATPVBAEN.XLAM!Regress", Range(sDepVarRange & lRows), Range("D3:G" & lRows), False,
True, , _
 sSheetName, False, False, True, True, , False

sSheetName = "FS,PC,FLUID DIVIDED BY PI"
DeleteSheet sSheetName
Application.Run "ATPVBAEN.XLAM!Regress", Range(sDepVarRange & lRows), Range("E3:G" & lRows), False,
True, , _
 sSheetName, False, False, True, True, , False

sSheetName = "FS,PC"
DeleteSheet sSheetName
Application.Run "ATPVBAEN.XLAM!Regress", Range(sDepVarRange & lRows), Range("E3:F" & lRows), False,
True, , _
 sSheetName, False, False, True, True, , False

sSheetName = "LL,FS,PC"
DeleteSheet sSheetName
Application.Run "ATPVBAEN.XLAM!Regress", Range(sDepVarRange & lRows), Range("D3:F" & lRows), False,
```

```
True, , _
  sSheetName, False, False, True, True, , False

sSheetName = "PI"
DeleteSheet sSheetName
Application.Run "ATPVBAEN.XLAM!Regress", Range(sDepVarRange & lRows), Range("H3:H" & lRows), False,
True, , _
  sSheetName, False, False, True, True, , False

sSheetName = "LL,FS"
DeleteSheet sSheetName
Application.Run "ATPVBAEN.XLAM!Regress", Range(sDepVarRange & lRows), Range("D3:E" & lRows), False,
True, , _
  sSheetName, False, False, True, True, , False

sSheetName = "FLUID DIVIDED BY PI,PI"
DeleteSheet sSheetName
Application.Run "ATPVBAEN.XLAM!Regress", Range(sDepVarRange & lRows), Range("G3:H" & lRows), False,
True, , _
  sSheetName, False, False, True, True, , False

sSheetName = "FLUID DIVIDED BY PI"
DeleteSheet sSheetName
Application.Run "ATPVBAEN.XLAM!Regress", Range(sDepVarRange & lRows), Range("G3:G" & lRows), False,
True, , _
  sSheetName, False, False, True, True, , False

Application.ScreenUpdating = True

Sheets("Data").Select
```

```
VBA.MsgBox "Done"


End Sub

Sub DeleteSheet(sName As String)

Dim osht As Object


For Each osht In ActiveWorkbook.Sheets

  If VBA.UCase(osht.Name) = sName Then

    Application.DisplayAlerts = False

    Sheets(sName).Select

    ActiveWindow.SelectedSheets.Delete

    Application.DisplayAlerts = True

    Exit For

  End If

Next osht


Sheets("DATA_ANALYSIS").Select


End Sub
```